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FINANCIAL ANALYSIS
&
ECONOMIC EVALUATION OF
THE CONCEPT OF
COGENERATION
FOR THE
VICTORIA METROPOLITAN
AREA

Energy, Mines and Resources Canada
Conservation and Renewable Energy Branch

Energie, Mines et Ressources Canada
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Ministry of Energy, Mines and Petroleum Resources
CONSERVATION AND TECHNOLOGY DIVISION

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A Report to
Energy Conservation & Technology Division
Ministry of Energy Mines & Petroleum Resources
Government of British Columbia

&
Capital Regional District
Victoria, British Columbia

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by

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The responsibility for the content of this report is the Consultants' alone, and the conclusions reached herein do not necessarily reflect the opinions of those who assisted during the course of this investigation or the Federal and Provincial governments which funded the study.

PREFACE

This report, entitled "Financial Analysis & Economic Evaluation of the Concept of Cogeneration in the Victoria Metropolitan Area", produced by Richard J. Brewer & Associates Ltd., forms an addendum to, and should be read in conjunction with, the technical report produced by B.H. Levelton & Associates Ltd. entitled "A Feasibility Study of the Concept of Cogeneration for the Victoria Metropolitan Area".

Due to the extent of the financial analysis, the report is divided into three parts. A brief summary of each part is as follows:-

PART I

PART I of the report represents the principal undertaking in the financial analysis and concentrates upon identifying and developing the potential annual cash flows that would be experienced if a Cogeneration plant was constructed in the Victoria Metropolitan Area. However, it should be noted that the Cogeneration plant and its alternative steam distribution systems are considered in isolation and the financial analysis does not account for any other method of refuse disposal that may be required to operate in conjunction with a Cogeneration plant. In particular, no costs have been included for disposing of refuse that cannot be accommodated at the plant.

As one of the the terms of reference of the Feasibility Study, was to establish a procedure upon which to evaluate the economics of the concept of cogeneration in areas, other than the Victoria Metropolitan Area, considerably emphasis has been placed upon the explanation of the methodology adopted in the financial analysis.

PART I concludes with the selection of two particular cases which could prove economically viable in the long term.

PART II

PART II of the report concentrates on comparing the financial implications of cogeneration with those of alternative methods of refuse disposal in the Victoria Metropolitan Area. However, in order to achieve a fair comparison, the financial results obtained for the two cases of cogeneration defined in PART I, had to be slightly modified. The modifications were necessary in order to incorporate additional costs associated with the disposal of refuse that cannot be accommodated by the Cogeneration plant but nevertheless require disposal by some other means. PART II concludes by demonstrating the preferable long term financial benefits of cogeneration over either of the two alternative methods of refuse disposal.

PART III

PART III of the report concentrates on financing the initial short term but substantial negative cash flows of cogeneration. Several options are reviewed and PART III concludes with an illustration of how three of the options can all be equitably utilized to finance the short term negative cash flows.

It should be stressed that no attempt has been made to furnish in the report a recommendation for either the construction of a Cogeneration plant in the Victoria Metropolitan Area or if the Cogeneration plant was constructed, the method of financing the plant. The intent of the report is to primarily produce sufficient financial data upon which public authorities can develop their own conclusions and make the appropriate decisions.

TABLE OF CONTENTS

TITLE

PART I - FINANCIAL ANALYSIS & ECONOMIC EVALUATION OF THE CONCEPT OF COGENERATION IN THE VICTORIA METROPOLITAN AREA

SECTION 1.00 INTRODUCTION

SECTION 2.00 METHODOLOGY

2.01 General

2.02 Refuse Produced within VMA

2.03 RDF Produced from Refuse

2.04 Volume of Refuse which cannot be Processed at the Plant

2.05 First Year of Operation of Phase II

2.06 Revenue from the Sale of Steam

2.07 Revenue from the Sale of Electricity

2.08 Revenue from the Sale of Ferrous Metals

2.09 Capital Costs

2.10 Amortization of Capital Costs

2.11 Operating Expenses for the Power Plant

2.12 Operating Expenses for the Refuse Plant

2.13 Operating Expenses for the Steam and Electrical Distribution System

2.14 Disposal Costs for Inert Material

2.15 Fuel Costs for Standby Boiler

2.16 Period of Simulation

2.17 Tabulation of Results

SECTION 3.00 MARKETS FOR THE SALE OF STEAM

3.10 General

3.20 Steam Distribution System I

3.30 Steam Distribution System II

3.40 Steam Distribution System A

3.50 Steam Distribution System B

3.60 Steam Distribution System C

3.70 Steam Distribution System D

3.80 Steam Distribution System E

SECTION 4.00 VALUES OF VARIABLES ENTERED INTO THE FINANCIAL MODEL

4.10 Capital Cost

4.20 Revenues

4.30 Power Plant Expenditures

4.40 Refuse Plant Expenditures

4.50 Distribution System Expenditures

4.60 Disposal Costs

4.70 Fuel Costs

4.80 Financial Data

4.90 Miscellaneous

SECTION 5.00 RESULTS OF THE FINANCIAL ANALYSIS

5.10 General

5.20 Explanation of Tables

5.30 Basis of Comparative Analysis

5.40 Selection of Most Economically Viable Steam Distribution System

5.50 Electrical Generation

5.60 Sensitivity Analysis

5.70 Conclusions

PART II - COMPARISON OF FINANCIAL RESULTS OF ALTERNATIVE METHODS OF REFUSE DISPOSAL

SECTION 1.00 INTRODUCTION

SECTION 2.00 LANDFILL

SECTION 3.00 INCINERATION PLANT

SECTION 4.00 COGENERATION

SECTION 5.00 CONCLUSIONS

PART III - ALTERNATIVE OPTIONS FOR FINANCING INITIAL YEARS NEGATIVE CASH FLOWS

SECTION 1.00 INTRODUCTION

SECTION 2.00 SELF FINANCING

SECTION 3.00 GOVERNMENT GRANT

SECTION 4.00 CAPITAL REGIONAL DISTRICT PROPERTY TAXES

SECTION 5.00 COMMERCIAL REFUSE DISPOSAL FEE

SECTION 6.00 CONCLUSIONS

APPENDIX I - TABLES

TABLE I SUMMARY OF FINANCIAL RESULTS

TABLE II SENSITIVITY ANALYSIS

TABLE III SENSITIVITY ANALYSIS

TABLE IV FINANCIAL COMPARISON OF ALTERNATIVE REFUSE DISPOSAL METHODS

TABLE V EFFECT ON FINANCIAL RESULTS DUE TO DIRECT GRANT APPLIED TO CAPITAL COSTS

TABLE VI PERCENTAGE DISTRIBUTION OF NR TO REGIONAL MEMBERS OF THE CRD

TABLE VII COMPARISON OF MILL RATE FOR ALTERNATIVE REFUSE DISPOSAL METHDOS

TABLE VIII REVENUE RECEIVED FROM COMMERCIAL REFUSE DISPOSAL FEE

TABLE IX ILLUSTRATION OF A METHOD OF FINANCING NEGATIVE CASH FLOWS

APPENDIX II - GRAPHS

GRAPH I ANNUAL CASH FLOWS OF COGENERATION - SYSTEM A AND ALTERNATIVE METHODS OF REFUSE DISPOSAL

GRAPH II ANNUAL CASH FLOWS OF COGENERATION - SYSTEM D AND ALTERNATIVE METHODS OF REFUSE DISPOSAL

GRAPH III GROSS COST PER TON OF THREE ALTERNATIVE METHODS OF REFUSE DISPOSAL

GRAPH IV ILLUSTRATION OF METHOD OF FINANCING INITIAL ANNUAL NEGATIVE CASH FLOWS

APPENDIX III - INDEX TO VARIABLES USED IN FINANCIAL MODEL

APPENDIX IV - COMPUTER PROGRAM OF FINANCIAL MODEL

APPENDIX V - COMPUTER PRINTOUT OF RESULTS OF TWO SPECIFIC CASES

CASE 11 SYSTEM A - W/O II
CASE 14 SYSTEM D - W/O II

PART I

FINANCIAL ANALYSIS

&

ECONOMIC EVALUATION

OF THE CONCEPT OF

COGENERATION

IN THE

VICTORIA METROPOLITAN AREA

1.00 INTRODUCTION

A Feasibility Study of the Concept of Cogeneration for the Victoria Metropolitan Area (VMA) based on the use of Refuse Derived Fuel (RDF) was conducted by B.H. Levelton & Associates Ltd. with specialized technical assistance from Intercontinental Engineering Co. et al. The study concentrated on evaluating the technical requirements of a Cogeneration plant and also on optimizing the size and layout of the major components of the plant. The study identified construction costs and annual operating costs of the plant. The study also identified unit prices for steam and electricity that could realistically be charged to potential customers. A market analysis was conducted by D.W. Thomson Consultants Ltd. to determine the potential market for steam in the VMA. An estimate of the cost of constructing a small steam distribution system in the downtown core area, and also at the University of Victoria, were included in the analysis.

However, before any funds are committed to the construction of a Cogeneration plant, it is essential to determine the long term economic viability of the plant. In February 1981, Richard J. Brewer & Associates Ltd. were retained by the Capital Regional District (CRD) to conduct a financial analysis in order to evaluate the economic viability of a Cogeneration plant similar to that specified by the Engineering Consultants. This report, then, outlines the method of that study and identifies the potential financial revenues or deficits which could result from constructing a Cogeneration plant in the VMA.

2.00 METHODOLOGY

2.01 General

In order to assess the financial implications of constructing a Cogeneration plant, it is first necessary to determine the annual net operating cash flows for the initial year of operation, and a number of years thereafter. The cash flows, however, are dependent upon a large number of variables and also upon many interdependent relationships that exist between those variables. It was therefore decided that the most efficient method of financial analysis would be to construct a computer model of the Cogeneration plant.

The financial model was constructed on a Tektronix 4052 with an effective capacity of 64K. The degree of complexity and level of sophistication of the model can be judged by the fact that even this substantial capacity of the computer was fully utilized by the programme. However, it is intended to transfer the programme, entitled "COGEN", to the larger computer recently purchased by the CRD, once that computer becomes fully operable. Cash flows for additional years and other areas of interest can then be studied as required. For his considerable assistance in the programming of the model, Mr. R. Bennett, the resident computer specialist of the CRD, is gratefully acknowledged.

The financial model consists of a series of complex mathematical equations. However, no mathematical equations have been included in the report as it is considered that the internal mechanisms of the model would be better explained by the following descriptive accounts of the major components of the model and the variables that affect each component. However, for more detailed information regarding the Financial model, a copy of the complete computer program has been included in APPENDIX IV.

Many of the variables utilized in the financial analysis could have been incorporated in the financial model as constants. However, in order to give maximum flexibility to the model, the model, wherever possible, has been developed utilizing variables. APPENDIX III includes a complete index to the 140 variables utilized in the financial model. Those 65 variables identified by an asterisk (*) in the index are input variables which can be readily entered into the model. The expression "readily entered into the model" which is frequently used in this section, refers to an input variable whose value, once entered into the model, can be readily modified without having to modify the computer programme itself. The balance of the variables in the index are necessary for the operation of the model.

For ease of reference, many of the variables in the index are, where considered appropriate, identified in paranthesis in the descriptive account of the major components of the financial model which follows. Further, the 65 input variables, together with some of the operational variables, are again identified in Section "4.00 VALUES OF VARIABLES ENTERED INTO THE FINANCIAL MODEL".

Each of the input variables must have a value assigned to it prior to commencement of analysis. However, in order to avoid unnecessary time in entering the value of each input variable for each case to be analyzed, a Base Case, complete with values assigned to the input variables has been saved in the computer memory. The values assigned to the variables contained in the Base Case represent values which are, wherever possible, common to the values to be utilized for the other cases. Any other case can then be analyzed by simply recalling the Base Case and modifying only those values of the variables which require modification in order for them to conform to the values of the specific case that is being analyzed.

It should also be noted that, for brevity, standard conversion factors such as hours to days or years, etc., or per day or per hour,

etc., have been omitted from the descriptive accounts. However, these factors have been incorporated into the programme where appropriate. Further, the model is based upon 1981 dollars. Thus, any growth expressed in real terms implies a growth over and above the inflation rate.

2.02 Refuse Produced within Victoria Metropolitan Area

The model defines the average daily volume of refuse produced within the VMA [WO(n)], as the product of an initial daily volume of refuse produced in 1981 [G1(1)], and an annual percentage growth rate, [R1(1)]. These last two variables are readily entered into the model. It should be noted that the model recognizes the increase in daily volume of refuse during the period between 1981 and the first year of operation of the Cogeneration plant and will utilize the daily volume of refuse that is appropriate to the year that is being analyzed.

The daily volume of refuse produced in the VMA, and hence the RDF produced from the refuse plant, is not constant throughout the year; the maximum production occurring in the summer and the minimum production occurring in the winter. The model assumes a seasonal variation in the daily volume of refuse produced with the maximum and minimum expressed as a positive and negative percentage of the average daily volume of refuse produced. The model assumes a linear relationship in the daily volume of refuse produced throughout the year with the maximum occurring on the 1st July and the minimum occurring on the 1st January. The percentage in the seasonal variation in the average daily refuse produced is a variable [G1(6)], which can be readily entered into the model.

2.03 RDF Produced from Refuse

The model defines the daily volume of RDF produced from the refuse plant [W1(n)], as a percentage of the daily volume of refuse produced within the VMA. This percentage is a variable [G1(2)], which can be readily entered into the model.

2.04 Volume of Refuse which cannot be Processed at the Plant

The model defines the annual volume of refuse which cannot be processed at the plant as the sum of the annual volume of refuse which cannot be processed during the period the refuse plant is not in operation [X0(n)], and the annual volume of refuse which cannot be processed due to the limited capacity of the Cogeneration plant [X1(n)].

As little storage capacity exists in the Cogeneration plant, it has been assumed that the refuse plant will only be operating while the RDF boiler is operating. Thus, the availability of the refuse plant can be assumed to be equivalent to the availability of the RDF boiler.

The annual volume of refuse which cannot be processed during the period the refuse plant or the RDF boiler is not in operation [X0(n)], is defined as the product of the average daily volume of refuse produced within the VMA [W0(n)], and the number of days in the year less the availability of the RDF boiler [W3(1)]. The availability of the RDF boiler is defined in Subsection "2.06 Revenue from the Sale of Steam".

Every plant has a finite operating capacity and this is defined by the individual capacity of one or more components of the plant. In the case of the Cogeneration plant the capacity of the plant is limited by the size of the RDF boiler. The maximum capacity of the

RDF boiler in Phase I is 400 tons/day of RDF and the maximum capacity of the RDF boiler in Phase II is 600 tons/day of RDF. The model recognizes this limit in capacity and defines the limit by a variable [G1(8)], which can be readily entered into the model. It should be noted that values other than 400 and 600 can be assigned to this variable.

The model assumes that all refuse received at the refuse plant is converted to RDF and burnt in the RDF boiler. However, should the capacity of the RDF boiler be fully utilized, then any refuse arriving at the refuse plant which cannot be converted to RDF and burnt is diverted to an alternative method of refuse disposal. Thus, the model converts the limit of the RDF boiler into a maximum daily volume of refuse that can be accepted at the refuse plant. Should the daily refuse exceed this value, then the excess refuse cannot be accepted by the refuse plant and is diverted directly to an alternative method of refuse disposal. This situation occurs first, of course, in summer when the maximum refuse produced in any year occurs.

The calculation to determine the annual volume of refuse which cannot be processed due to the limited capacity of the Cogeneration plant [X1(n)], involves a series of complex equations with a number of different variables. For brevity, these equations are not reproduced here but they have been incorporated in the computer programme and the model will automatically test each year if any refuse cannot be accommodated by the plant and, if necessary, calculate the total annual volume of refuse that cannot be processed due to the limited capacity of the Cogeneration plant.

It should be noted that, in the event that any refuse during the year is diverted to an alternative method of refuse disposal, then the model will recalculate the average daily volume of RDF that is being processed for that particular year. The average daily volume of RDF

that is being processed will therefore initially grow at the same annual growth rate as that for the refuse produced in the VMA but, in the year that the first refuse is diverted to an alternative method of refuse disposal due to the limited capacity of the RDF boiler, the annual growth rate will decrease. The annual growth rate will continue to decrease and eventually reach zero when the average daily volume of RDF processed equals the maximum capacity of the RDF boiler. As the refuse diverted to an alternative method of refuse disposal involves disposal costs not associated with the Cogeneration plant, these costs have not been included in PART I of the financial analysis. These costs, however, are incorporated in the financial analysis performed in PART II of the report.

2.05 First Year of Operation of Phase II

The model defines the first year of operation of Phase II as the first year when the maximum daily volume of RDF processed, exceeds the capacity of the RDF boiler installed in Phase I [G1(8)]. The maximum daily volume of RDF processed, coincides with the maximum daily volume of refuse produced in the VMA and will occur in the summer of that year. In the year that this condition is reached, the model will automatically amortize the capital cost of Phase II, and include in the simulation the additional operating costs for Phase II.

2.06 Revenue from the Sale of Steam

The annual revenue received from the sale of steam is the product of the annual volume of steam that can be sold and the unit price that the steam can command in the market place.

The annual volume of steam sold in each year is obtained from the average hourly volume of steam sold. The average hourly volume of steam sold [V1(n)], is defined in the model by an average initial

hourly volume [V0(1)], an annual percentage growth rate [R1(2)], and an average maximum hourly volume [V0(3)]. These last three variables can be readily entered into the model to accommodate the various steam distribution systems outlined in SECTION "3.00 MARKETS FOR THE SALE OF STEAM". The model calculates the annual volume of steam sold as the product of the average daily volume of steam sold and the availability of the steam supply system. [W3(3)].

The availability of the steam supply system is defined in the model as the combined availability of the RDF boiler and the conventional fuel fired, or standby, boiler. The availability of the RDF boiler [W3(1)], is defined in the model as the product of the number of days in the year less the number of days for a planned shutdown of the RDF boiler [N1(4)], and the reliability of the RDF boiler [N1(5)]. The availability of the standby boiler [W3(2)], is defined in the model as the product of the period that the RDF boiler is not in operation, and the reliability of the standby boiler [N1(7)] . The period that the RDF boiler is not in operation is, in fact, the number of days in the year less the availability of the RDF boiler [W3(1)]. The number of days of the planned shutdown of the RDF boiler [N1(4)], the number of days of the planned shutdown of the standby boiler [N1(6)], together with the reliabilities of the RDF boiler [N1(5)], and the standby boiler [N1(6)], each expressed as a percentage, are all variables which can be readily entered into the model. It should be noted, however, that the planned shutdown of the standby boiler [N1(7)], is considered to occur during the availability of the RDF boiler [W3(1)], and, therefore, does not enter into the model's calculations. It is identified only for completeness.

The price of steam [P1(n)], is defined in the model by a 1981 unit price [P0(1)], and an annual percentage growth rate in real terms [R1(3)]. These last two variables can be readily entered into the model. It should be noted that the model recognizes the increase in the unit price that occurs between 1981 and the first year of

operation of the plant, and will utilize the price that is appropriate to the year that is being analyzed.

The printout identifies for each year the average hourly volume of steam that is being sold [V1(n)], the current unit price for steam [P1(n)], and the total annual revenue received from the sale of steam [Z1(n)].

2.07 Revenue from the Sale of Electricity

The annual revenue received from the sale of electricity is the product of the annual volume of electricity that can be sold and the unit price that the electricity can command in the market place.

It is assumed that all electricity generated can be sold but the annual volume of electricity generated is considerably more complex to determine than the annual volume of steam sold. The volume of steam sold is mutually exclusive to the volume of steam produced but the volume of electricity sold is not only, wholly dependent upon the volume of steam produced but also, dependent upon the volume of steam sold.

The volume of steam produced from the RDF boiler is calculated from the factor to convert one ton of RDF into X pounds of steam [J1]. The volume of steam produced from the standby boiler is calculated from an additional conversion factor which is defined as the number of Imperial gallons of oil required to produce the same volume of steam as one ton of RDF [J3]. These two variables can be readily entered into the model.

It was determined, during the financial analysis, that the calculation to determine the annual volume of electricity sold is complicated by the fact, that the quantity of electrical energy produced from one ton of RDF does not remain constant. The quantity

of electrical energy produced from one ton of RDF is dependent upon the ratio of the steam sold to the steam produced. For example, the quantity of electrical energy produced from one ton of RDF without any steam being sold is some 40% greater than if 50% of that steam was being sold. The Engineering Consultants gave three factors for the quantity of the electrical energy produced from one ton of RDF with each factor corresponding to a particular percentage of steam sold to that produced. A non-linear equation was developed by computer to fit all three co-ordinates and has been incorporated into the computer programme but, for reference, it is reproduced as the last statement on the case criteria sheet of the computer printout.

The case criteria sheet is that sheet which accompanies, but precedes, the computer printout of each of the cases that have been analysed. The case criteria sheet provides a ready means to identifying the values of the variables which have been utilized in the specific case analysed and which are also appropriate to the results that have been printed.

The model, therefore, computes the average hourly volume of steam produced [V5(n)], from the average daily volume of RDF being burnt, [W1(n)], then computes the ratio of the average hourly volume of steam sold to the average hourly volume of steam produced [W2(n)], and, finally computes, from the non-linear equation, the factor to convert one ton of RDF into X kilowatthours of electricity [J2(n)].

The total annual volume of electricity generated by the RDF boiler is calculated as the product of the unit quantity of electricity generated from one ton of RDF [J2(n)], the average daily volume of RDF being burnt [W1(n)], and the availability of the turbines while the RDF boiler is in operation [W3(4)].

The availability of the turbines while the RDF boiler is in operation [W3(4)], is defined in the model as the product of the number of days

in the year less the number of days of planned shutdown of the turbines [N1(8)], the reliability of the turbines expressed as a percentage [N1(9)], and the ratio of the availability of the RDF boiler [W3(1)], to the number of days in the year. The number of days of planned shutdown of the turbines [N1(8)], and the reliability of the turbines [N1(9)], are variables which can be readily entered into the model.

During the financial analysis it was determined that it was not economical to utilize conventional fuel in the standby boiler to produce steam and to generate electricity unless a market for that steam was available. Thus, at those times when the RDF boiler is not in operation, the standby boiler will only produce sufficient steam to satisfy the market demands and, consequently, the resulting electrical output during this period will be different to the electrical output during the operation of the RDF boiler.

It should be noted, however, that due to thermal losses, the volume of steam produced by either boiler must be greater than that which is actually sold. Therefore, another factor, which is a ratio expressed as a percentage, has been incorporated in the model. This ratio [V0(2)], is defined as the maximum volume of steam that could technically, be sold from a given quantity of fuel divided by the volume of steam that is, in fact, produced from that given quantity of fuel. This percentage is a variable which can be readily entered into the model.

Thus, during the period of operation of the standby boiler, the model will compute the factor to convert one ton of RDF into X kilowatt-hours of electricity, by utilizing this percentage [V0(2)], in the non-linear equation that was described earlier. The total annual volume of electricity generated by the standby boiler is thus calculated as the product of the unit quantity of electricity generated from one ton of RDF [J4], the factor to convert one ton of

RDF into a number of Imperial gallons of oil [J3], the average daily volume of RDF that would have been required to have been burnt to provide the required volume of steam that is being sold [W7(n)], and the availability of the turbines while the standby boiler is in operation [W3(5)].

The availability of the turbines while the standby boiler is in operation [W3(5)], is defined in the model as the product of the number of days in the year less the number of days of planned shutdown of the turbines [N1(8)], the reliability of the turbines expressed as a percentage [N1(9)], and the ratio of the availability of the standby boiler [W3(2)], to the number of days in the year. It should be noted that all these variables have been entered into model from previous requirements. Further the sum of the availability of the turbines while the RDF boiler is in operation and the availability of the turbines while the standby boiler is in operation has been defined as the availability of the electrical supply system and can be indentified on the case criteria sheet.

The total annual volume of electricity that is sold is therefore computed from the combined volumes of electricity generated by both the RDF boiler and standby boiler.

The price of electricity [P2(n)], is defined in the model by a 1981 unit price [P0(2)], and an annual percentage growth rate in real times [R1(4)]. These last two variables can be readily entered into the model. It should be noted that the model recognizes the increase in the unit price that occurs between 1981 and the first year of operation of the plant and will utilize the price that is appropriate to the year that is being analyzed.

The printout identifies, for each year, the average hourly electrical power being generated from the RDF boiler [V2(n)], the unit price of electricity, [P2(n)], and the total annual revenue received from the sale of all the electricity generated [Z2(n)].

It should be noted that, as the plant is considered to be reliable in the generation of electricity, then an additional revenue can be obtained from the purchaser of the electricity. The model defines this revenue as a fixed monthly income which remains constant in 1981 dollars. This variable [P0(4)], can be readily entered into the model. The annual revenue from this source [Z3(n)], can be identified on the printout.

2.08 Revenue from the Sale of Ferrous Metals

The annual revenue received from the sale of ferrous metals is the product of the annual volume of ferrous metals that are recovered from the refuse and the unit price that ferrous metals can command in the market place. It is assumed that all ferrous metals that can be recovered are indeed, sold.

The model defines the annual volume of ferrous metals that are recovered from the refuse as the product of the daily volume of ferrous metals that are sold [V4(n)], and the availability of the RDF boiler [W3(1)]. The daily volume of ferrous metals that are sold is defined in the model as a percentage [G1(4)], of the daily wet refuse produced in the VMA. This variable can be readily entered into the model.

The price of ferrous metals [P4(n)], is defined in the model by a 1981 unit price [P0(5)], and an annual percentage growth rate in real terms [R1(5)]. These last two variables can be readily entered into the model. It should be noted that the model recognizes the increase in the unit price that occurs between 1981 and the first year of operation of the plant and will utilize the price that is appropriate to the year that is being analyzed.

The printout identifies, for each year, only the total annual revenue received from the sale of ferrous metals [Z4(n)].

2.09 Capital Costs

The net capital cost of the Cogeneration plant is divided into the first (I) and second (II) Phase. The model calculates the net capital cost of Phase I [CO(7)], as the sum of the total construction cost [CO(1)], the design/legal fees [CO(2)], the capital cost of land [C1(1)], the interim financing [CO(3)], and the contingency [CO(4)], or government grant [CO(6)], if any.

The model defines the total construction cost for Phase I [CO(1)], as the sum of the following four variables: the construction cost of the power plant for Phase I only [C1(2)]; the construction cost of the refuse plant [C1(4)]; the construction cost of the steam distribution system [C1(5)]; and, the construction cost of the electrical distribution system [C1(6)]. These four variables can be readily entered into the model.

The model defines the design/legal fees as a product of a percentage and the total construction cost for Phase I. The percentage is a variable [D1(1)], which can be readily entered into the model.

The model defines the capital cost of land as a variable [C1(1)], which can be readily entered into the model.

The model defines the interim financing as the product of an interest rate and the sum of the total construction cost for Phase I [CO(1)], the design/legal fees [CO(2)], and the capital cost of land [C1(1)]. The interest rate is a variable [D1(2)], which can be readily entered into the model. It should be noted that the construction period of the Cogeneration plant is for two years. Thus, the interest is charged for one year on the full amount. It should also be noted that the interest should be entered into the model in absolute values as the model will discount the interim financing by one year at the rate of inflation.

The model defines the contingency [C0(4)], as the product of a percentag. and the sum of the total construction cost for Phase I [C0(1)], the design/legal fees [C0(2)], the capital cost of land [C1(1)], and the interim financing [C0(3)]. The percentage is a variable [D1(4)],which can be readily entered into the model. The net capital cost of both Phases can be readily adjusted by this variable.

The model defines the government grant [C0(6)], in exactly the same way as the contingency except that the government grant, when entered into the model as a positive percentage [D1(3)], is computed as a negative percentage.

The model calculates the net capital cost of Phase II [C0(8)], in exactly the same manner as the net capital cost of Phase I. However, it should be noted that, as the construction period for Phase II is only one year, the interim financing is based upon only half a year.

The construction cost of the power plant for Phase II [C1(3)], is a variable which can be readily entered into the model. It should be noted that, if this variable is set to zero, the model will assume that Phase II will not become operational when required.

2.10 Amortization of Capital Costs

The model amortizes the net capital cost for Phase I into equal annual payments of principal and interest [W4(2)], over the amortization period utilizing a standard accounting formula. Interest is calculated at the end of each year when the single annual payment of principal and interest is made. The amortization rate [I2] and amortization period [N1(3)], are two variables which can be readily entered into the model.

Each annual payment is discounted to 1981 dollars by the rate of inflation. The rate of inflation is a variable [I1] which can be readily entered into the model.

The model amortizes the net capital cost for Phase II in exactly the same manner as for Phase I and utilizes the same values for the amortization period and rate of inflation that were entered for Phase I. It should be noted that the model inflates the capital cost of both Phases up to the year prior to the operation of each Phase before the capital cost is amortized and the annual payments are discounted to 1981 dollars.

The model computes the principal sum remaining on the debt for the capital cost of Phase II at the end of the period of simulation of the model and prints this sum [W4(6)], on the case criteria sheet of the computer printout. The printout identifies, for each year, the sum of the discounted values of principal and interest for both Phase I and Phase II [Z5(n)].

2.11 Operating Expenses for the Power Plant

The model defines the annual operating expenses for the power plant for Phase I as the sum of the total annual maintenance costs, the total annual labour costs, the total annual general costs, and the total annual power costs.

The total annual maintenance costs of the power plant [01(n)], are defined by the model as an initial annual maintenance cost [00(1)], and an annual percentage growth rate in real terms [R1(6)]. These two variables can be readily entered into the model.

The total annual labour costs of the power plant [02(n)], are defined by the model as a fixed annual labour cost in real terms. This variable [00(3)], can be readily entered into the model.

The total annual general costs of the power plant [03(n)], are defined in the model as a product of a fixed annual general cost in real terms and the percentage contingency applied to the net capital cost [D1(4)]. This relationship was developed to account for higher insurance premiums, etc., required with larger insurance coverage. The variable for the fixed annual general costs [00(5)], can be readily entered into the model.

The total annual power costs of the power plant [05(n)], are defined by the model as the product of the total annual electrical power requirement [04(n)], of the power plant, the unit selling price of electricity [P2(n)], as defined earlier in Subsection "2.07 Revenue from the Sale of Electricity", and a factor to adjust the selling price of electricity to the commercial buying price of electricity. The purchase to selling factor for electricity is a variable [P0(3)], which can be readily entered into the model.

The total annual electrical power requirement of the power plant is the annual electrical power required to operate the plant and is defined in the model as the product of an initial power requirement, the availability of the electrical supply system, and the ratio of the steam produced by the RDF boiler [V5(n)], to the steam produced by the RDF boiler in the first year of operation [V5(1)]. The initial power requirement is a variable [00(7)], which can be readily entered into the model. It should be noted that the model assumes that the power plant requires power for 24 hours per day.

The annual operating expenses of the power plant for Phase II are computed by the model in exactly the same manner as for Phase I. It should be noted, however, that all the costs are additional costs in real terms over and above the Phase I costs in real terms . The three marginal costs for initial annual maintenance costs [00(2)], fixed annual labour costs [00(4)], and fixed annual general costs [00(6)], are variables which can be readily entered into the model.

No additional power costs have been assumed, as they will automatically be accommodated in the model by the increase in steam produced by the Phase II RDF boiler. The model also assumes that the annual percentage growth rate in maintenance costs [R1(6)], is the same as for Phase I.

The printout identifies, for each year, the total annual sum of the operating expenses for the combined phases of the power plant [Z6(n)].

2.12 Operating Expenses for the Refuse Plant

The model defines the annual operating expenses for the refuse plant for Phase I as the sum of the total annual maintenance costs, the fixed annual labour costs, the total annual general costs, and the total annual power costs of the refuse plant.

The total annual maintenance costs of the refuse plant [M1(n)], are defined by the model as the product of the daily volume of RDF processed in the plant [W1(n)], the availability of the RDF boiler [W3(1)], and the unit maintenance cost per ton of RDF.

The unit maintenance cost per ton of RDF is defined in the model by an initial unit maintenance cost per ton of RDF and an annual percentage growth rate in real terms. The annual percentage growth rate is identical to that utilized for the maintenance costs in the power plant [R1(6)], but the initial unit maintenance cost is a variable [M0(1)], which can be readily entered into the model.

The total annual labour costs of the refuse plant [M2(n)], are defined by the model as a fixed annual labour cost in real terms. This variable [M0(2)],can be readily entered into the model.

The total annual general costs of the power plant [M3(n)], are defined in the model as a product of a fixed annual general cost in real terms and the percentage contingency applied to the capital cost [D1(4)]. This relationship was developed to account for higher insurance premiums, etc., required with larger insurance coverage. The variable for the fixed annual general cost [M0(4)], can be readily entered into the model.

The total annual power costs of the refuse plant [M5(n)], are defined by the model as the product of the total annual electrical power requirement of the refuse plant [M4(n)], the unit selling price of electricity [P2(n)], as defined earlier in Subsection "2.06 Revenue from the Sale of Electricity", and a factor to adjust the selling price of electricity to the commercial buying price of electricity [P0(3)]. The purchase to selling factor for electricity is identical to that utilized in the power costs for the power plant.

The total annual electrical power requirement of the Refuse plant is the annual electrical power required to operate the plant and is defined in the model as the product of the daily volume of RDF processed in the plant [W1(n)], the availability of the RDF boiler [W3(1)], and the unit electrical power required to process one ton of RDF. The unit electrical power required to process one ton of RDF is a variable [M0(6)], which can be readily entered into the model.

As stated earlier, it should again be emphasized that the model assumes that the refuse plant will only be operating while the RDF boiler is operating. Thus, the availability of the RDF boiler is equivalent to the availability of the refuse plant.

The annual operating expenses of the refuse plant for Phase II are computed by the model in exactly the same manner as for Phase I. It should be noted that the annual labour costs for Phase II are additional costs in real terms over and above the Phase I labour

costs. This marginal cost is a variable [MO(3)], which can be readily entered into the model. No additional annual general costs have been assumed for Phase II as no additional equipment is required in Phase II. No additional annual maintenance or power costs have been assumed for Phase II as they will automatically be accommodated in the model by the increase in the volume of RDF processed.

The printout identifies, for each year, the total annual sum of the operating expenses for the combined phases of the refuse plant [Z7(n)].

2.13 Operating Expenses for the Steam and Electrical Distribution System

The model defines the total annual operating expenses for the steam and electrical distribution system as the product of the sum of the construction costs of the steam distribution system [C1(5)], and electrical distribution system [C1(6)], and a percentage of that sum. The percentage is a variable (T1), which can be readily entered into the model. The total annual operating expenses are expressed in fixed annual amounts in real terms.

The printout identifies, for each year, the fixed operating expenses for the steam and electrical distribution system [ZO(n)].

2.14 Disposal Costs for Inert Material

The model defines the total annual costs for disposing of inert material as the sum of the total annual cost of disposing of ash and the total annual cost of disposing of noncombustible material.

The model defines the total annual cost of disposing of ash [07(n)], as a product of the daily volume of ash generated from the RDF boiler, the availability of the RDF boiler [W3(1)], and the unit cost of disposing of ash. The daily volume of ash generated from the RDF

boiler is defined by the model as the daily volume of refuse produced in the VMA [W0(n)], and a percentage of that refuse that is converted to ash. The percentage is a variable [G1(5)], which can be readily entered into the model.

The model defines the unit cost of disposing of ash as the product of an initial unit cost of disposing of ash in 1981 [00(8)], and an annual percentage growth rate in real terms [R1(7)]. These two variables can be readily entered into the model. It should be noted that the model recognizes the increase in the unit price that occurs between 1981 and the first year of operation of the plant and will utilize the price that is appropriate to the year that is being analyzed.

The model defines the total annual cost of disposing of noncombustible material [M7(n)], as a product of the daily volume of noncombustible material received and sorted at the refuse plant, the availability of the RDF boiler [W3(1)], and the unit cost of disposing of noncombustible material.

The daily volume of noncombustible material received and sorted at the Refuse plant is defined by the model as the daily volume of refuse produced in the VMA [W0(n)], and a percentage of that refuse that is noncombustible material. The percentage is a variable [G1(3)], which can be readily entered into the model. The unit cost of disposing of noncombustible material is identical in value to the unit cost of disposing of ash.

The printout identifies, for every year, the total annual sum of disposing of both ash and noncombustible material [Z8(n)].

2.15 Fuel Costs for Standby Boiler

The model defines the total annual cost of fuel for the standby boiler as the sum of the annual cost of fuel for the standby boiler during the period that the RDF boiler is not in operation, and for the annual cost of fuel for the standby boiler during "winter makeup".

The model defines the annual cost of fuel for the standby boiler during the period that the RDF boiler is not in operation [09(n)], as the product of the annual volume of fuel required to generate sufficient steam to satisfy the customer demand for steam, and the price of fuel. The model defines the annual volume of fuel required to generate sufficient steam to satisfy the customer demand for steam [08(n)], as the product of the average daily volume of fuel required to generate sufficient steam for customer demand and the availability of the standby boiler [W3(2)]. The model computes the average daily volume of fuel required to generate sufficient steam to satisfy customer demand not only from the two conversion factors [J1] and [J3], and one efficiency factor [V0(2)], defined in Subsection "2.06 Revenue from the Sale of Stream" and Subsection "2.07 Revenue from the Sale of Electricity" respectively, but, also from the minimum average daily volume of RDF that is needed to generate sufficient steam in order to satisfy the average hourly volume of steam that is being sold [W7(n)].

The model defines the price of fuel as a 1981 unit price [P0(6)], and an annual percentage growth rate in real terms [R1(8)]. These two variables can be readily entered into the model. It should be noted that the model recognizes the increase in the unit price that occurs between 1981 and the first year of operation of the plant, and will utilize the price that is appropriate to the year that is being analyzed.

During the financial analysis, it was determined that situations could occur whereby insufficient RDF was being produced and burnt to generate sufficient steam to satisfy customer demand. Thus, it is necessary to supplement the steam generated by the RDF boiler with steam generated by the standby boiler. This situation particularly occurs during the winter periods and is therefore entitled "winter makeup". The sale of steam is not constant throughout the year with the maximum demand occurring in winter and the minimum demand occurring in summer. The model assumes a seasonal variation in the volume of steam sold and this is expressed as a percentage of the average volume of steam sold. The model assumes a linear relationship in the daily volume of the steam sold throughout the year with a maximum occurring on the 1st January, and a minimum occurring on the 1st July. The percentage in the seasonal variation of steam sold [G1(7)] can be readily entered into the model.

The calculation to determine the annual volume of fuel required to supplement the RDF boiler during "winter makeup" [W8(n)], involves a lengthy and complex equation with a number of different variables. For brevity, the equation is not reproduced here but it has been incorporated into the computer programme and the model will automatically tested each year if any "winter makeup" fuel is required and, if necessary, will calculate the annual volume of fuel needed to supplement the RDF boiler. The annual cost of "winter makeup" fuel [W9(n)], is the product of the annual volume of fuel required for "winter makeup" and the price of fuel. The price of fuel for "winter makeup" is identical to the price of fuel utilized for the standby boiler during the period that the RDF boiler is not in operation.

The printout identifies, for each year, the total annual sum of the fuel costs required for the standby boiler, resulting from the period the RDF boiler is not in operation and/or "winter makeup" [Z9(n)].

2.16 Period of Simulation

The model defines the period of simulation as the number of annual cash flows which the model will analyze. This number is a variable [N1(2)], which can be readily entered into the model.

2.17 Tabulation of Results

The model consolidates into one variable [Y1(n)], the total revenue received from the sale of steam [Z1(n)], from the sale of electricity [Z2(n) and Z3(n)], and from the sale of ferrous metals [Z4(n)], for each year. The printout identifies, for each year, the total annual revenue received in that year.

The model consolidates into one variable [Y2(n)], for each year, the total expenditures resulting from the amortization of capital costs [Z5(n)], the total annual operating costs of the power plant [Z6(n)], the total annual operating costs of the refuse plant [Z7(n)], the total annual operating costs of the distribution systems [Z0(n)], the total annual disposal costs of inert material [Z8(n)], and the the total annual cost of fuel for the standby boiler [Z9(n)]. The printout identifies, for each year, the total annual operating expenditures for that year.

The model consolidates into one variable [Y3(n)], the net revenue or expenditure, for each year, by subtracting the total operating expenditures [Y2(n)], from the total revenue received [Y1(n)]. The printout identifies, for each year, the net revenue or expenditure.

The model calculates the cumulative net revenue or expenditure, [Y4(n)], for each year, from the sum of the net revenue or expenditure of the previous years, and the net revenue or expenditure of the current year that is being analyzed. The printout identifies, for each year, the cumulative total net revenue or expenditure for that year.

The model calculates the cumulative net revenue or expenditure, with interest on the net expenditure [Y5(n)], in the same manner as for the cumulative net revenue or expenditure. However, should a net expenditure occur, then interest is charged on the total amount that has to be carried forward from a previous year to the next year. The interest rate that is applied is the interest rate entered for the variable for interim financing [D1(2)]. The interest rate, however, is discounted into real terms by the annual rate of inflation. The printout identifies, for each year, the cumulative total net revenue or expenditure with interest on the net expenditure for that year.

The model defines the average daily volume of disposable material [Y8(n)], as the sum of the total annual volume of wet refuse that cannot be processed at the plant during the period the RDF boiler is not in operation [X0(n)], the total annual volume of wet refuse that cannot be processed at the plant due to the limited capacity of the Cogeneration plant [X1(n)], the total annual volume of ash produced by the plant [06(n)], and the total annual volume of noncombustible material obtained from wet refuse [M6(n)], all divided by the number of days in the year. The printout identifies, for each year, the average daily volume of disposable material for that year.

The model defines the average annual gross processing cost per ton [Y6(n)], as the net revenue or expenditure, divided by the total annual volume of wet refuse produced in the VMA. The printout identifies, for each year, the average gross process cost per ton of refuse for that year.

The model defines the average annual net processing cost per ton [Y7(n)], as the net revenue or expenditure divided by the total annual volume of refuse that is actually processed through the refuse plant. The printout identifies, for each year, the average net processing cost per ton of refuse for that year.

3.00 MARKETS FOR THE SALE OF STEAM

3.10 General

The Engineering Consultants examined in detail two potential markets for the sale of steam which were; the downtown core area, and the University of Victoria. A steam distribution system was developed for each of these markets and the respective construction and operating costs for each system were estimated.

The two steam distribution systems do not accommodate any expansion into the known larger markets for the sale of steam. Thus, more extensive steam distribution systems are necessary to reach these markets, and the construction and operating costs of these expanded systems must be included in the financial analysis of the Cogeneration plant. Five such systems were selected during the financial analysis and their construction costs were estimated. The construction cost of each system was based upon the linear quantity of piping within each system and various unit construction rates. Various unit construction rates were utilized to reflect the various degrees of subsurface congestion that may be encountered by the piping when it is installed beneath the streets. The five steam distribution systems and the markets they serve are described in more detail below. The two initial steam distribution systems examined by the Engineering Consultants are also included.

However, it should be noted that the initial steam distribution system, designed for the downtown core area, assumed that the Cogeneration plant could be constructed in the vicinity of the Parliament Buildings. It is considered, however, that even if a suitable site for a plant could be found in this vicinity, it is unlikely to receive public endorsement as the appearance of the building and the increase in heavy truck traffic could prove to be unacceptable. The nearest area which is considered to be acceptable

to the public, and which also offered an opportunity to expand into the known larger markets for the sale of steam, was considered to be located between Government Street and the Inner Harbour and north of Pandora Street. No attempt has been made to enquire whether any particular site is available for purchase and, if so, at what price. However, for purposes of financial analysis, $600,000 per acre has been assumed for the purchase price of land. This value has been determined from a preliminary examination of real estate values in that particular area which is zoned for industrial use. For the purposes of estimating linear quantities of piping, the corner of Government Street and Discovery Street has been assumed to represent the starting point of the steam distribution system.

The purchase price of land in the vicinity of the Parliament Buildings was assumed, for purposes of financial analysis, to be twice the value of land in the Government Street/Inner Harbour/North of Pandora Street area. The purchase price of land in the vicinity of the University of Victoria was assumed, for purposes of financial analysis, to be half the value of land in the Government Street/Inner Harbour/North of Pandora Street area.

3.20 Steam Distribution System I

a) General

The location of the Cogeneration plant is in the vicinity of the Parliament Buildings. Steam Distribution System I has been described in the text prepared by the Engineering Consultants, and is designed to service the downtown core area. The construction cost of Steam Distribution System I is estimated to be $2.7 million.

b) Initial Volume of Steam Sold

The following facilities are assumed to be connected to the steam distribution system at the commencement of operation of the Cogeneration plant.

Ref. No.	Facility	Annual BTU x 10^6
1	Parliament Buildings	59,500
13	Empress Hotel	40,820
34	Victoria General Hospital	49,400
47	Crystal Gardens	9,940
	Total	159,660

This total annual quantity of thermal energy required by the facilities is equivalent to an average initial volume of steam sold of 16,500 lbs/hr.

c) Maximum Volume of Steam Sold

Steam Distribution System I does not permit the connection of additional facilities without incurring additional construction costs. The maximum average volume of steam sold, therefore, remains at the initial level of 16,500 lbs/hr.

3.30 Steam Distribution System II

a) General

Steam Distribution System II has been described in the text prepared by the Engineering Consultants and is designed to serve the University of Victoria. The location of the Cogeneration plant is in the vicinity of the University of Victoria. The construction cost of Steam Distribution System II is estimated to be $1.8 million.

b) Initial Volume of Steam Sold

The following facilities are assumed to be connected to Steam Distribution System II at the commencement of the operation of the Cogeneration plant:-

Ref.	Facility	Annual BTU x 10^6
38	Clearhue Boiler Plant	47,600
39	Commons Boiler Plant	11,300
40	McKinnon Boiler Plant	17,300
41	Remainder Boiler Plant	18,000
	Total	93,900

The total annual quantity of thermal energy required by these facilities is equivalent to an average initial volume of steam sold of 10,000 lbs/hr.

c) Maximum Volume of Steam Sold

Steam Distribution System II does not permit the connection of additional facilities without incurring additional construction costs. The maximum average volume of steam sold, therefore, remains at the initial level of 10,000 lbs/hr.

3.40 Steam Distribution System A

a) General

The location of the Cogeneration plant is in the Government Street/Inner Harbour/North of Pandora Street area but will provide steam for the same downtown core area as in Steam Distribution System I. The main steam line is assumed therefore to run along Government Street, Humboldt Street, Douglas Street, and connect into Steam Distribution System I. Three short spur lines, which will run a short distance along View Street, Fort Street, and Burdett Street, are also included in this system. The total construction cost of Steam Distribution System A is estimated to be $7.5 million.

b) Initial Volume of Steam Sold

All the facilities identified in Steam Distribution System I are assumed to be connected to Steam Distribution System A at the commencement of the operations of the plant. The average initial volume of steam sold is therefore assumed to be 16,500 lbs/hr.

c) Maximum Volume of Steam Sold

The following additional facilities are assumed to be connected to Steam Distribution System A during the period of operation of the Cogeneration plant:-

Ref. No.	Facility	Annual BTU x 10^6
11	Centennial Square	6,190
15	Executive House Hotel	4,200
30	Royal Trust Building	4,200
31	Central Building	4,500
32	Canada Trust Building	1,100
33	Yarrow Building	5,200
42	Customs Building	2,320
43	Post Office Building	2,900
44	Eatons Department Stores	10,820
48	Union Club	3,250
49	Labatts Brewery	31,320
	Total	76,000

The total annual quantity of thermal energy required by these facilities is equivalent to an average volume of steam sold of 8,000 lbs/hr. The maximum average volume of steam sold for Steam Distribution System A is therefore 24,500 lbs/hr.

3.50 Steam Distribution System B

a) General

Steam Distribution System B is identical to Steam Distribution System A with the exception that additional spur lines have been included. New spur lines have been added to run along Herald Street, Pandora Street, and Courtney Street, while the spur lines in View Street, Fort Street, and Burdett Street have been extended. The total construction cost of Steam Distribution System B is estimated to be $13.9 million.

b) Initial Volume of Steam Sold

As in the case of Steam Distribution System A, all the facilities identified in Steam Distribution System I are assumed to be connected to Steam Distribution System B at the commencement of the operations of the Cogeneration plant. The average initial volume of steam sold is therefore assumed to be 16,500 lbs/hr.

c) Maximum Volume of Steam Sold

All the additional facilities identified in Steam Distribution System A, together with the following additional facilities, are assumed to be connected to Steam Distribution System B during the period of operation of the Cogeneration plant:-

Ref. No.	Facility	Annual BTU x 10^6
3	Waddington Building	8,120
4	Law Courts	5,800
5	Richard Blanshard	8,700
6	St. Anne's Academy	5,220
7	780 Blanshard	1,740
12	Royal Theatre	2,610
14	Chateau Victoria Hotel	11,600
16	Strathcona Hotel	3,712
17	Royal Olympic Hotel	3,400
20	Courtyard Inn Hotel	2,800
21	Bank of Commerce Building	7,356
22	Royal Bank Building	2,000
24	Wilson Centre	3,250
25	International	4,350
26	Bentall Building	4,520
27	Montreal Trust Building	2,500
28	Sayward Building	3,100
29	Toronto Dominion Bank Building	2,020
45	Bay Store	9,758
56	YMCA/YWCA	9,512
	TOTAL=	102,068

The total annual quantity of thermal energy required by these facilities is equivalent to an average volume of steam sold of 10,500 lbs/hr. The maximum average volume of steam sold for Steam Distribution System B is therefore 35,000 lbs/hr.

3.60 Steam Distribution System C

a) General

Steam Distribution System C assumes that the location of the Cogeneration plant is in the Government Street/Inner Harbour /North of Pandora Street area but will provide steam primarily for the Royal Jubilee Hospital. The main steam line is assumed, therefore, to run along Discovery Street and Pembroke Street. Two small spur lines have been included which will run along Blanshard Street and Quadra Street. The total construction cost of Steam Distribution System C is estimated to be $8.2 million.

b) Initial Volume of Steam Sold

The only facility which is assumed to be connected to Steam Distribution System C at the commencement of operations of the plant is the Royal Jubilee Hospital. The total annual quantity of thermal energy required by this facility is 105,060 BTU x 10^6 which is equivalent to an average initial volume of steam sold of 11,000 lbs./hr.

c) Maximum Volume of Steam Sold

The following additional facilities are assumed to be connected to Steam Distribution System C during the period of operation of the Cogeneration plant:-

Ref. No.	Facility	Annual BTU x 10^6
9	Crystal Pool	14,060
10	Arena	2,810
49	Labatts Brewery	31,320
	Total	48,190

The total annual quantity of thermal energy required by these facilities is equivalent to an average volume of steam of 5,000 lbs/hr. The maximum average volume of steam sold for Steam Distribution System C is therefore 16,000 lbs/hr.

3.70 Steam Distribution System D

a) General

Steam Distribution System D is a combination of Steam Distribution System A and Steam Distribution System C. The system will therefore provide steam to both the downtown core area and the Royal Jubilee Hospital. The total construction cost of Steam Distribution System D is estimated to be $15.7 million.

b) Initial Volume of Steam Sold

All the facilities identified in Steam Distribution System I, together with the Royal Jubilee Hospital, are assumed to be connected to Steam Distribution System D at the commencement of the operations of the Cogeneration plant. The average initial volume of steam sold is therefore 27,500 lbs/hr.

c) Maximum Volume of Steam Sold

All the additional facilities identified in Steam Distribution System A, together with the Crystal Pool and Arena, are assumed to be connected to Steam Distribution System D during the period of operation of the Cogeneration plant. The total annual quantity of thermal energy required by these facilities is is equivalent to an average volume of steam sold of 9,500 lbs/hr. The maximum average volume of steam sold for Steam Distribution System D is therefore 37,000 lbs/hr.

3.80 Steam Distribution System E

a) General

Steam Distribution System E is a combination of Steam Distribution System B and Steam Distribution System C. The system will therefore provide steam to nearly all of the downtown area and also the Royal Jubilee Hospital. The total construction cost of Steam Distribution System E is estimated to be $22.1 million.

b) Initial Volume of Steam Sold

As in the case of Steam Distribution System D, all the facilities identified in Steam Distribution System I, together with the Royal Jubilee Hospital, are assumed to be connected to Steam Distribution System E at the commencement of the operations of the Cogeneration plant. The average initial volume of steam sold is therefore 27,500 lbs/hr.

c) Maximum Volume of Steam Sold

All the additional facilities identified in Steam Distribution System B, together with the Crystal Pool and Arena, are assumed to be connected to Steam Distribution System System E during the period of operation of the Cogeneration plant. The total annual quantity of thermal energy required by these facilities is equivalent to an average volume of steam sold of 20,000 lbs/hr. The maximum average volume of steam sold for Steam Distribution System E is therefore 47,500 lbs/hr.

4.00 VALUES OF VARIABLES ENTERED INTO THE FINANCIAL MODEL

4.10 Net Capital Cost to CRD for Phase I [C0(7)] and Phase II [C0(8)]

a) Capital Cost of Land [C1(1)]

The technical report indicated that an area of 2.5 acres would be required for the Cogeneration plant and, based on the unit cost of land as described in Subsection "3.10 General", the following capital costs for land have been utilized in the financial model.

Steam Distribution System	Capital Cost of Land
System I	$3.2 million
System II	$0.8 million
Systems A to E	$1.6 million

b) Power Plant Construction Cost for Phase I [C1(2)] and Phase II [C1(30]

The technical report indicates that the construction cost of Phase I of the power plant would be $19.9 million in 1980 dollars but this amount excluded contractors' profit and overhead, etc. Therefore, approximately 25 per cent has been added to this base price for contractors' profit and overhead and also for inflation in order to bring the construction cost into 1981 dollars. However, the Engineering Consultants have recently introduced a modification in the boiler design which could realize a potential saving of $500,000. The total construction cost of Phase I of the power plant is therefore assumed to be $24.5 million.

Based on a similar rationale, the construction cost of Phase II of the power plant has been increased from $7.12 million and is now assumed to be $9.0 million in 1981 dollars.

c) Refuse Plant Construction Cost [C1(4)]

The technical report indicates that the construction cost of the refuse plant would be $5,475,000. However, this amount included a $1 million contingency and $450,000 for engineering fees. The total construction cost of the refuse plant is therefore assumed to be $5 million in 1981 dollars.

d) Steam Distribution System Construction Costs [C1(5)]

The steam distribution systems have been described in "Section 3.00 MARKETS FOR THE SALE OF STEAM". The following table summarizes the construction cost of the steam distribution systems in 1981 dollars.

System	Construction Cost
System I	$ 2.7 million
System II	$ 1.8 million
System A	$ 7.5 million
System B	$13.9 million
System C	$ 8.2 million
System D	$15.7 million
System E	$22.1 million

e) Electrical Distribution System Construction Cost [C1(6)]

The technical report indicates that the construction cost of the electrical distribution system would be $336,000. However, $400,000 has been assumed as the construction cost of the electrical distribution system in 1981 dollars.

f) Design/Legal Fees [D1(1)]

It has been assumed that the design/legal fees will approximate 10 per cent of the total construction cost.

4.20 Revenues [Y1(n)]

a) Volume of Steam Sold [V1(n)]

The volumes of steam sold which correspond to the various steam distribution systems have been described in Section "3.00 MARKETS FOR THE SALE OF STEAM". The following table summarizes the average initial hourly volume of steam sold [V0(1)] and the average maximum hourly volume of steam sold [V0(3)], for each steam distribution system:-

System	Volume of Steam Sold	
	Initial lbs/hr.	Maximum lbs/hr.
System I	16,500	16,500
System II	10,000	10,000
System A	16,500	24,500
System B	16,500	35,000
System C	11,000	16,000
System D	27,500	37,000
System E	27,500	47,500

It is assumed that the initial volume of steam will be sold to those customers that have been identified by the facilities in Section "3.00 MARKETS FOR THE SALE OF STEAM". However, if these customers do not wish to modify their choice of fuel for heating their facilities, and the required initial volume of sales cannot be achieved through alternative customers on that particular steam distribution system, then it is assumed that the system will not be installed.

The annual percentage growth in the average hourly volume of steam sold [R1(2)], is extremely difficult to predict but a value of 5 per cent per year has been assumed. The initial volume of steam sold will therefore grow by this percentage every year until the maximum volume of steam sold is reached.

b) Price of Steam Sold [P1(n)]

The Engineering Consultants have recommended a price of $9.00 per 1000 lbs/hr. for the 1981 price of steam sold [P0(1)]. This price is based on the equivalent heating value for natural gas on Vancouver Island, together with a 15 per cent discount, which has been applied in order to attract the potential customers. The price also reflects the low thermal efficiencies of natural gas burners in commercial operation together with other operating costs.

The Engineering Consultants have recommended that a value of 5 per cent per year in real terms over and above inflation, be utilized for the annual percentage growth in the price of steam [R1(3)]. This value reflects a combination of an accelerating demand for energy with a depleting supply of natural resources.

c) Price of Electricity Sold [P2(n)]

The technical report has indicated a price of 12 mills per kilowatthour for the price of electricity sold in 1980 dollars. Therefore, the price of electricity in 1981 [P0(2)], is assumed to be 13 mills per kilowatthour.

The Engineering Consultants have recommended that a value of 2 per cent per year in real terms be utilized for the annual percentage growth in the price of electricity sold [R1(4)]. This value reflects the general increase in energy prices but makes accommodation for the large renewable hydro-electric resources of British Columbia.

The Engineering Consultants have recommended that, due to the potential continuity of electrical generation from the power plant, the monthly revenue from electrical reliability [P0(4)], can be assumed to be $15,000 per month.

d) Price of Ferrous Metals [P4(n)]

The Engineering Consultants have recommended the 1981 price ferrous metal sold, [P0(5)], F.O.B. at the plant gate to be $25 per ton of ferrous metal.

The Engineering Consultants have recommended that a value of 1 per cent per year in real terms should be utilized for the annual percentage growth in the price of ferrous metals [R1(5)]. This value reflects a marginal increase in base commodity prices over the long term.

4.30 Power Plant Expenditures [Z6(n)]

a) Maintenance Costs [01(n)]

The technical report indicates that the average maintenance cost for Phase I of the power plant is $450,000 per year in 1980 dollars for a 25 year period. However, to reflect increasing costs due to wear and tear of equipment, the initial annual maintenance cost for Phase I [00(1)], has been assumed to be $350,000 per year in 1981 dollars, and a value of 2 per cent per year in real terms has been assumed for the annual percentage growth in maintenance costs [R1(6)]. This value is the mean value of 2 1/2 per cent per year and 1 1/2 per cent per year, which the Engineering Consultants recommended for the growth in maintenance costs for the power plant and refuse plant, respectively.

The Engineering Consultants have indicated that Phase II of the power plant would have an additional initial annual maintenance [00(2)], cost of $100,000 per year in 1981 dollars for the first year of its operation. The growth in maintenance costs have been assumed by the financial model to be identical to the value utilized in Phase I.

b) Labour Costs [02(n)]

The technical report indicates that the labour costs of operating Phase I of the power plant would be $419,000 per year in 1980 dollars. Therefore, fixed annual labour costs for Phase I [00(3)], have been assumed to be $470,000 in 1981 dollars.

Similarly, the Engineering Consultants have indicated that the additional fixed annual labour costs of Phase II [00(4)], of the power plant would be $120,000 per year in 1981 dollars.

c) General Costs [03(n)]

The technical report indicates that general costs of operating Phase I of the power plant would be be $175,000 per year in 1980 dollars. Therefore, the fixed annual general costs for Phase I [00(5)], have been assumed to be $200,000 per year in 1981 dollars.

Similarly, the Engineering Consultants has indicated that the additional fixed annual general costs for Phase II [00(6)], of the power plant would be $50,000 per year in 1981 dollars.

d) Power Costs [04(n)]

The technical report indicates that the power plant will consume 1900 horsepower or 1417 kilowatthours if all equipment is being fully utilized. The initial power requirement [00(7)], has therefore been assumed to be approximately half that value or 750 kilowatthours.

The technical report indicates that the selling price of electricity is approximately 75 per cent of the purchase price. Therefore, a value of 1.33 has been assumed to be the purchase to selling factor for electricity [P0(3)].

4.40 Refuse Plant Expenditures [Z7(n)]

a) Maintenance Costs [M1(n)]

The Engineering Consultants have recommended that the maintenance costs of the refuse plant, should be equivalent to an initial unit maintenance cost per ton of RDF processed [M0(1)], of $2.00 per ton of RDF. The financial model assumes the same value for the growth in maintenance costs for the refuse plant as utilized for the growth in maintenance costs for the power plant. This value is the mean value of 2 1/2 per cent per year and 1 1/2 per cent per year, which the Engineering Consultants recommended for the growth in maintenance costs for the power plant and refuse plant, respectively.

b) Labour Costs [M2(n)]

The technical report indicates that the labour costs of operating Phase I of the refuse plant is $379,400 per year in 1980 dollars. Therefore, the fixed annual labour costs for Phase I (M0(2)], have been assumed to be $420,000 in 1981 dollars.

Similarly, the technical report indicates that the additional fixed annual labour costs for Phase II [M0(3)], of the refuse plant should be $300,000 per year in 1981 dollars.

c) General Costs [M3(n)]

The technical report indicates that the general costs of operating Phase I of the Refuse plant would be $100,000 per year in 1980 dollars. Therefore, the fixed annual general costs [M0(4)], have been assumed to be $110,000 per year in 1981 dollars.

d) Power Costs [M5(n)]

The technical report indicates that the refuse plant will consume 2100 horsepower or 1567 kilowatthours if all the equipment is being fully utilized. This condition is assumed to occur when the plant is operating at its maximum capacity, i.e. 400 tons of RDF produced in an 8 hour shift. The unit power requirement to process one ton of RDF [M0(6)], is therefore assumed to be 30 kilowatts per ton of RDF.

The purchase price of electricity for the refuse plant is identical to that utilized for the power plant.

4.50 Distribution System Expenditures [Z0(n)]

The technical report indictes that the cost of operating the steam distribution system would be $16,000 per year, and $12,000 per year for System I and System II, respectively. No operating costs of the electrical distribution system have been provided but they are considered to be small. The fixed steam and electrical distribution costs are defined as a percentage of the combined construction cost of the steam and electrical distribution system (T1), the percentage has therefore, been assumed to be 0.6 per cent.

4.60 Disposal Costs [Z8(n)]

The technical report assumes that the cost of disposing of ash is $10 per ton of ash. The 1981 disposal cost per ton of ash [00(8)], and the 1981 disposal cost of noncombustible materials [M0(5)], have therefore, been assumed to be, $10 per ton of ash and $10 per ton of noncombustible materials.

The annual percentage growth in disposal costs [R1(7)], has been assumed to be 2.5 per cent per year, in real terms, which reflects the real increase in the cost of transportation.

4.70 Fuel Costs [Z9(n)]

The Engineering Consultants have recommended that the cost of natural gas used to feed the standby boiler would be equivalent to a 1981 purchase price per Imperial gallon of oil [P0(6)], of 80 cents per Ig.

The growth in the price of natural gas is assumed to be identical to the growth in the price of steam sold, which is 5 per cent per year in real terms.

4.80 Financial Data

With the current rate of inflation at 12 per cent per year, and with little indication that inflation will subside in the forseeable future, the annual rate of inflation [I1], has been assumed to be 12 per cent per year. The annual amortization rate of the loans [I2], has been assumed to be 25 per cent higher than the rate of inflation, and is therefore assumed to be 15 per cent per year in money terms. The interest rate for interim financing [D1(2)], has been assumed to be 50 per cent higher than the rate of inflation, and is therefore assumed to be 18 per cent per year in money terms. It is understood that the maximum period of amortization of a loan that the Capital Regional District can obtain is 25 years, and therefore, the amortization period of the loans for both Phase I and Phase II [N1(3)] has been assumed to be 25 years.

4.90 Miscellaneous

a) Refuse Produced in the Victoria Metropolitan Area [W0(n)]

The Engineering Consultants have advised that the value for the initial average daily wet refuse produced in the VMA for 1981 [G1(1)], should be 438 tons per day. The annual percentage

growth in refuse produced in the VMA [R1(1)], is assumed to be equivalent to the growth in population in the VMA which is currently estimated to be 2.3 per cent per year.

Table XIII of the technical report indicates that the following values should be utilized for the by-products obtained from the refuse.

RDF produced from wet refuse [G1(2)]	50.0%
Noncombustible material in wet refuse [G1(3)]	18.7%
Ferrous metals obtained from wet refuse [G1(4)]	4.2%
Ash produced from wet refuse [G1(5)]	4.0%

b) Planned Downtime and Reliability of Equipment

The Engineering Consultants have recommended that the following values for planned downtime and reliability of the equipment should be utilized in the financial analysis.

Planned downtime of RDF boiler [N1(4)]	14 days
Planned downtime of standby boiler [N1(6)]	5 days
Planned downtime of turbines [N1(8)]	10 days
Reliability of RDF boiler [N1(5)]	98%
Reliability of standby boiler [N1(7)]	98%
Reliability of turbines [N1(9)]	96%

c) Length of Simulation [N1(2)]

The length of simulation of the financial analysis has been assumed to be 25 years. However, 25 years is recommended as an upper limit for the period of simulation while the programme remains on the Tektronix 4052 as the computer memory becomes fully utilized beyond that period.

d) Miscellaneous

The Engineering Consultants have advised that the following values should be utilized in the financial analysis.

1 Ton of RDF produces 8800 lbs of Steam at 600 psig at 750°F [J1]

1 Ton of RDF is equivalent in heating value to 64.17 Imperial gallons of Oil [J3]

Seasonal Variation in Refuse Produced in the VMA [G1(6)] = 32%

Seasonal Variation in Steam Sold [G1(7)] = 75%

Maximum Capacity of RDF Boiler for Phase I [G1(8)] = 400 Tons/day

Maximum Capacity of RDF Boiler for Phase II [(G1(8)] = 600 Tons/day

Maximum Volume of Steam Sold to Steam Produced [V0(2)] = 77%

5.00 RESULTS OF FINANCIAL ANALYSIS

5.10 General

Utilizing the financial model described in Section "2.00 METHODOLOGY" and entering the values for the variables given in Section "4.00 VALUES OF VARIABLES ENTERED INTO THE FINANCIAL MODEL", a financial analysis was conducted on the feasibility of cogeneration in the VMA. Seven cases were initially analysed with each case corresponding to a different steam distribution system and steam market as described in Section "3.00 MARKETS FOR THE SALE OF STEAM. The seven cases assumed that Phase II of the Cogeneration plant would automatically become operational in the year when it was justified by the volume of refuse produced in the VMA. However, as it became evident during the analysis that little additional revenue was being gained for the increase in expenditures resulting from operating Phase II, the seven cases were again analysed but this time without Phase II becoming operational.

For illustration purposes, the complete computer printout of the results of two of the fourteen cases have been included in APPENDIX V. However, for ease of reference, the financial results of greatest interest that emerged from the analyses have been summarized in TABLE I for all fourteen cases. TABLE I and all subsequent tables are located in APPENDIX I. The various titles and abbreviations utilized in this table and other tables to follow are explained below.

5.20 Explanation of Tables

An explanation of the titles and abbreviations used in the tables and elsewhere in the report is as follows:-

CASE NUMBER

Refers to the number given to a particular case which has been filed in the memory of the computer. The complete case can be recalled from the computer memory by this number.

CASE TITLE

Refers to the title given to the case number. The title of the case incorporates one or more of the following:-

i) Name of the particular steam distribution system being analyzed;

ii) Abbreviations w/II or w/oII, which refer to whether the analysis was conducted with Phase II in operation or without Phase II in operation;

iii) Abbreviation w/oELECT which refers to the analysis being conducted without electrical power generation being included in the Cogeneration plant;

iv) Abbreviations Cont50%, Cont25%, Grant25%, Grant50%, which refer to the analysis being conducted using a contingency or grant of 50% or 25% applied to the Total Capital Cost;

v) Abbreviations INF8%, and INF16% which refer to the analysis being conducted using a value for the rate of inflation of 8% or 12%;

vi) Abbreviation SP6 and SP12 which refer to the analysis being conducted using a value for the selling price of steam of $6.00 and $12.00 per 1000 lbs./hour;

vii) Abbreviation Rel77% which refers to the analysis being conducted using a value for the reliability of the RDF boiler of 77%.

NR

Refers to NET REVENUE OR EXPENDITURE for each year and can be identified on the computer printout. The term can also be considered as the positive or negative annual cash flow.

CNR

Refers to the CUMULATIVE NET REVENUE OR EXPENDITURE of all annual cash flows up and including the year being reviewed. The term can be identified on the computer printout. The term can also be considered as the net present value of the sum of all the streams of cash flows up to the year being reviewed.

CNR+I

Refers to the CUMULATIVE NET REVENUE OR EXPENDITURES WITH INTEREST ON NET EXPENDITURES. The term can be identified on the computer printout. It is similar to the term CNR but interest has been charged on all negative CNR. The term CNR+I can also be loosely considered as the "investment and opportunity cost" of the case up to the year being reviewed.

LAST YEAR OF NEGATIVE NR

Refers to the last year in which the annual cash flow is negative. The following year is the first year in which the annual revenues from cogeneration exceed the annual operating expenditures.

NPC

Refers to NET PROCESS COST and can be identified on the computer printout. The term refers to the avarage cost of processing only the refuse that actually passes through the Cogeneration plant. It does not account for refuse that is unable to be received by the plant.

GPC

Refers to GROSS PROCESSING COST. The term refers to the average cost of processing refuse in the VMA. It encompasses the cost for the operation of other facilities that are required, in addition to the prime method of refuse disposal and is related to the gross volume of refuse produced in the VMA. Although this term can also be identified on the computer printout, it should be stressed that its value does not include any costs associated with the operation of

other refuse disposal methods. These additional costs, however, effect the value of the GPC given on the computer printouts by less than $1 per ton.

5.30 Basis of Comparative Analysis

Although several financial parameters have been provided in TABLE I for each case, it is recommended that the column entitled Year 2009-CNR should be used as the basis for evaluating the financial merits of each case. This column represents the summation of the discounted cash flows for each year for a period of 25 years. The value obtained from this column for each case would therefore be equivalent to the Net Present Value (NPV) of all cash flows discounted back to the current year of 1981. It is recognized that the traditional definition of NPV has not, in this case, been rigourously applied as the financing costs have been included in the operating costs. However, out of a number of financial parameters that could have been obtained from a financial analysis, the NPV is considered to be the most appropriate for evaluating alternative strategies for the investment of public funds. Thus, the values shown in column "Year 2009-CNR" would best reflect the potential economical viability of the cases to which these values correspond. Further, based upon these values in this column, a quantitative comparison of the financial merits of one case to that of any other case can be made.

Although the column entitled "Year 2009-CNR" will be utilized as the basis of comparative analysis, mention should also be made of the column entitled "Year 2009-CNR+I". It can be argued that this column represents the "investment and opportunity cost " to the owner of the particular system under review. As the total capital cost of the cogeneration programme has been amortized, then only in those years in which the annual cash flows (NR) are negative will the owner be required to finance from his own source of funds. If the funds

required to balance the negative cash flows were instead committed to an alternative investment, the minimum return on which is assumed to be the equivalent to the rate of interim financing, then those funds would accumulate to the value of CNR+I. Thus, for any year the value of CNR+I would represent the "investment and opportunity cost" of the owner's funds. This value should not be taken as the basis for comparing alternative cogeneration systems or refuse disposal methods but its value is a useful guide to the owner for indicating the real cost of implementing any system over a period of time.

5.40 Selection of Most Economically Viable Steam Distribution System

From TABLE I, and using column "Year 2009-CNR" as the basis of comparative analysis, it can be seen that the cost to the CRD for operating Phase II would be approximately $20.0 million more, over the next 25 years, than if Phase II was not implemented. This would appear to be applicable no matter which of the seven steam distribution systems are considered.

Thus, in view of the substantial difference in operating costs between a system which incorporates Phase II and the same system which does not incorporate Phase II, it would appear that the construction of Phase II cannot be justified. Indeed, the additional financial burden of increased debt and operational costs associated with Phase II absorbs some of the potential revenues received from Phase I just at the time when Phase I is first producing positive cash flows. It should be noted, however, that had Phase II been justified, then it would be required to be fully operational in 1996.

Further analysis on any system which incorporates Phase II will not, therefore, be conducted unless some comparison is required for reference purposes. In addition, for ease of reference, the total system encompassing both the Cogeneration plant without Phase II in operation, and the respective steam distribution system which the

information. However, each variable, if modified, would affect, to some degree, the financial results of the analysis. An exhaustive analysis was not conducted in order to determine the variables which, if modified by a unit percentage, would produce the greatest changes in the financial results. However, four variables were selected by inspection, which were considered to affect the financial results most significantly, and which were considered to be either beyond the control of the estimator or which a greater degree of uncertainty had been incorporated in the value of that variable. The four variables are:

i) Total Capital Cost
ii) Rate of Inflation
iii) Selling Price of Steam in 1981
iv) Reliability of the RDF Boiler

Each one of these variables will be analyzed separately by increasing and decreasing the value of the variable by a fixed amount and determining the financial results.

b) Total Capital Cost

The estimate of the total capital cost of the Cogeneration plant must be viewed as preliminary and therefore contains a degree of uncertaintly with respect to the final costs. This, together with possibly abnormal inflation or market conditions at the time of tendering, could increase the capital cost considerably, even in 1981 dollars. However, some of the costs could be financed by a direct government grant, in which case the total capital costs could be reduced. To accommodate these two possibilities a financial analysis was conducted on both SYSTEM A and SYSTEM D with an increase and decrease in total capital costs of 25 per cent and 50 per cent. TABLE II summarizes the results of these analyses.

c) Rate of Inflation

The rate of inflation over the next 25 years cannot be predicted with any accuracy. However, in order to accommodate this degree of uncertainty, a financial analysis was conducted on both SYSTEM A and SYSTEM D with an inflation rate of 8 per cent and 16 per cent. It should be noted that the amortization rate has been modified to 10 per cent and 20 per cent respectively and the interim financing has been modified to 12 per cent and 24 per cent respectively to correspond to the different rates of inflation. TABLE III summarizes the results of these analyses.

d) Selling Price of Steam

The initial selling price of steam is largely dependent upon whether natural gas is available to the VMA and what selling price the natural gas can command. In order to accommodate this degree of uncertainty, a financial analysis was conducted on both SYSTEM A and SYSTEM D with a selling price of steam of $6 per 1000 lbs./hour and $12 per 1000 lbs./hour. TABLE III summarizes the results of that analysis.

e) Reliability of RDF Boiler

Preliminary analysis indicated that the financial results of the Cogeneration plant could be adversely affected if the RDF boiler was unable to be operated for any length of time. The variable that represents this degree of uncertainty in the operational performance of the RDF boiler is the reliability of the RDF boiler. The Engineering Consultants have indicated that the reliability of the RDF boiler could drop to a low of 77 per cent. Thus, a financial analysis was conducted on SYSTEM A and SYSTEM D utilizing the value of 77 per cent for the reliability of the RDF boiler. TABLE III summarizes the results of that analysis.

5.70 Conclusions

As discussed earlier, SYSTEM A and SYSTEM D would appear the most economically attractive SYSTEMS to implement at this stage of development. SYSTEM I, SYSTEM II and SYSTEM C, although all producing a positive cash flow by the year 2009, all have a negative NPV over the 25 year period of operation of the plant, indeed, in some cases by quite a substantial amount. These three SYSTEMS all have one major difference to the other four SYSTEMS that were analyzed. This common difference is the limited market for the sale of steam. With all three SYSTEMS, the maximum volume of sales of steam is either equal to or close to the initial volume of sales of steam. Thus it can be concluded that the key to the sussess of cogeneration is securing large steam markets. Without these markets, the steam, which is being produced irrespective of market demand, would merely go to waste without generating any revenue to offset the operating expenses. It is thus essential before any SYSTEM is installed to obtain committments for the purchase of steam from the potential customers for steam.

The CRD is fortunate in that, for either SYSTEM A or SYSTEM D, the majority of the facilities upon which the initial volume of sales of steam is based, are under the control of either Provincial, Regional or Municipal authorities and, thus, securing their committments to purchase steam may be less difficult to obtain than from private owners. Nevertheless, additional sales of steam will be required in order to maximize potential revenues, and thus an aggressive marketing policy will be necessary to achieve this objective.

The financial results as summarized in TABLES I, II and III are, in general, self explanatory and only minimum comment is considered necessary.

It may be of interest to note, that in addition to these results, the Internal Rate of Return was calculated for the two SYSTEMS considered

to be the most economicaly viable. The Internal Rate of Return was found to be approximately 1.5% and 6.0% in real terms for SYSTEM A and SYSTEM D respectively.

Further, it is also interesting to note that the sensitivity analysis performed on SYSTEM A and SYSTEM D indicates that, despite variations of up to 50 per cent on the values of the four critical variables, cogeneration could still prove to be economical in the long run. It can be seen that the net annual cash flow for each system is positive by the year 2009 or would become positive shortly thereafter.

The major effect of utilizing values of variables which differ slightly from the values that were assumed in the financial analysis, is to shift the graphical plot of "NR" against "Years". The graphical plot of "NR" against "Years" represents the line which results from graphically plotting the values of the net annual cash flow of each year against the corresponding year in which the net annual cash flow occurred, examples of which are shown in GRAPH I and GRAPH II. This plot line will tend to shift towards either the positive or negative side of that axis which is defined by a zero value for the net annual cash flow. However, it should also be noted that, as the plot line shifts, so the last year of negative cash flow will also shift. Thus, if a value of a variable affects the financial results in an adverse way, then the last year of negative cash flow will shift to a later year.

Thus, in summary, providing that the values of the variables do not, in practice, differ significantly from the assumed values in the financial analysis, then cogeneration would appear to be economically viable, if not immediately then possibly within the 25 year period of analysis and most probably within the 50 year estimated life of the plant. Indeed, if all steam markets were fully utilized, as in the case of SYSTEM E, then the potential net revenue accumulated over the first 25 years alone could exceed $65.0 million.

PART II

COMPARISON
OF
FINANCIAL RESULTS
OF
ALTERNATIVE METHODS
OF
REFUSE DISPOSAL

1.00 INTRODUCTION

Part I of the report has demonstrated that a Cogeneration plant could prove economically viable in the VMA over the long term. However, before any funds can be committed to the construction of such a plant, a financial analysis of the alternative methods of disposing of refuse within the VMA is required. A quantitative comparison can then be made between the financial implications of operating a Cogeneration plant and the financial implications of operating an alternative method of refuse disposal.

The CRD, together with the Engineering Consultants, have researched over the last four years a number of alternative methods of refuse disposal. Of these, only two alternative methods of disposal can still be considered to offer practical solutions to the disposal of refuse in the VMA, and even one of these alternatives may prove to be publicly unacceptable to implement. The two alternatives are: (a) the development of a new landfill site, and (b) the incineration of the refuse.

The Engineering Consultants provided first order estimates of the capital and operational costs for each of these facilities and, by selecting pertinent variables, the financial model was utilized in analyzing the annual cash flows. Throughout, 1981 dollars have been utilized and the period of operation and analysis corresponds to the time frame that was utilized for the Cogeneration plant.

The financial results of the two alternatives and the Cogeneration plant are reviewed below.

2.00 LANDFILL

The Engineering Consultants estimated that the total capital cost of a new landfill site, if a suitable location could be found, would be approximately $16.0 million in 1981 dollars. This would include the purchase of some 50 acres of land, improvements to the land to render it impermeable to prevent leachate from contaiminating the groundwater and for other environmental controls required by regulatory agencies. Interim financing, design fees and other expenses are also included in that total.

The total capital costs were amortized over 25 years at an amortization rate of 15 per cent per year in money terms. The annual payments were discounted to 1981 dollars utilizing an inflation rate of 12 per cent per year.

The operating costs of the landfill site would be, initially, approximately $500,000 per year in 1981 dollars. A growth rate of 2.5 per cent per year in real terms was included in order to accommodate the high maintenance costs associated with the wear of the equipment. A unit cost of $2.50 per ton of refuse was also included in the financial analysis in order to conform to the regulation which requires the covering of the refuse with cover material after each day of operation.

The results of the financial analysis for a new landfill site appear in TABLE IV and are plotted on GRAPHS I and II. It should be noted that in TABLE IV the financial results of year 1994 have been included. Year 1994 represents the tenth year of operation of any of the refuse disposal methods utilized but it also represents the last year of negative cash flow for SYSTEM A. Thus, the years beyond 1994, for both SYSTEM A and SYSTEM D, will experience positive cash flows.

3.00 INCINERATION PLANT

The Engineering Consultants estimated tht the total capital cost of Phase I for an Incineration plant would be approximately $16.0 million in 1981 dollars. This would include the construction of an Incineration plant with all associated costs. The cost of land is not included in this estimate because it has been assumed that the plant would be constructed at the existing landfill site. Although Phase II would be required in 1996 at a cost of $4.0 million in 1981 dollars in order to accommodate the growth in refuse in the VMA, Phase II has not been included in the analysis in order to achieve an equitable economic comparison with the Cogeneration plant. Phase II of the Cogeneration plant was shown to be uneconomical to implement.

The total capital costs were amortized over 25 years at an amortization rate of 15 per cent per year in money terms. The annual payments were discounted to 1981 dollars utilizing an inflation rate of 12 per cent per year.

The labour and general costs of the incineration plant would be fixed at approximately $600,000 per year in 1981 dollars. However, the maintenance cost would be approximately $2.50 per ton of refuse in 1981 dollars with a growth rate of 2 per cent per year in real terms to accommodate for the increase in maintenance costs with time. In addition, $3.00 per ton of refuse is required for the disposal of ash, supplementary fuel, etcetera.

Also included in the financial analysis is the cost of disposal of the excess refuse, which cannot be incinerated after 1996. This cost has been assumed to be $5.50 per ton in 1981 dollars which conforms to the calculated cost of disposal of refuse at the existing landfill site. This cost was primarily determined for the Cogeneration plant and is described in more detail in the following Subsection.

The results of the financial analysis for the Incineration plant appear in TABLE IV and are plotted on GRAPHS I and II.

4.0 COGENERATION

The financial analysis described in PART I of the report concentrated on the specific operations of the Cogeneration plant. It did not fully encompass the overall operation of refuse disposal within the VMA. As explained in PART I of the report, but again emphasized here, the Cogeneration plant, at certain times, will not be capable of receiving any refuse at all. This occurs particularly when the RDF boiler is not in operation. Further, without Phase II in operation, it is anticipated that from 1996 onwards, the VMA will be producing more refuse than the plant can handle. This will initially occur in the summer months. Although some storage of refuse is possible within the Cogeneration plant, it is assumed that the refuse which cannot be accepted, either due to the RDF boiler not being in operation or the insufficient capacity of the plant, will be diverted to the existing landfill site. The costs of this disposal must therefore be taken into consideration if an equitable comparison is to be achieved between the operation of a Cogeneration plant and any other method of refuse disposal in the VMA.

The annual operating costs of disposing of refuse which cannot be accepted at the plant has been assumed to be the product of a unit cost of disposal of refuse and the annual tonnage of refuse diverted to the landfill site. The unit cost of disposal was determined from a financial analysis of the previously described new landfill site. However, in this specific case, the amortization of capital costs were excluded from the annual cash flows of the financial analysis as the existing landfill site has already been purchased and any ongoing costs associated with the original purchase will be common to any method of disposal. From the analysis, the cost of disposal of refuse by landfill and exclusive of land financing costs, ranged from $5.35 in 1985 to $5.49 in 2009 with both values in 1981 dollars. The unit cost of disposal of refuse has therefore been assumed to be constant at $5.50 per ton of refuse.

The results of the financial analysis for SYSTEM A and SYSTEM D, modified to incorporate disposal costs for refuse diverted to the existing landfill site, appear in TABLE IV and are plotted on GRAPHS I and II.

It may be of interest to note that it is anticipated that, during the period from 1985 to 2009, some 5.83 million tons of refuse will be produced within the VMA. The Cogeneration plant will produce some 1.21 million tons of inert material such as ash and noncombustible material which may have to be disposed of at the landfill site. In addition, some 0.48 million tons of refuse will have to be diverted to the landfill site either due to the RDF boiler not being in operation, or insufficient capacity of the Cogeneration plant. This quantity could increase if the RDF boiler proves to be less reliable than the analysis had assumed.

With the estimated 1981 annual rate of refuse produced within the VMA at 160,000 tons per year, the existing landfill site requires at least a further 3 year capacity beyond 1985 in order to accommodate the refuse diverted during the 25 year period of operation of the Cogeneration plant. Thus, it would imply that the existing landfill site should have, from 1981 onwards, a capacity of at least seven years at current refuse production rates. As there is a finite limit to the capacity of any landfill site, it is imperative that this long lead time be recognized at an early stage in order to reserve adequate capacity for refuse which requires disposal in the landfill site during the periods of both construction and operation of a Cogeneration plant. However, it should also be recognized that a Cogeneration plant will extend the life of the existing landfill site by approximately 8 years for every year of operation of the plant.

5.00 CONCLUSIONS

In reviewing the financial results of the two alternatives to cogeneration, refuse disposal by incineration appears to be more expensive than refuse disposal by landfill. It should be noted, however, that considerable time and effort has been expended by the CRD in its search for a suitable site for septage disposal. Any site deemed technically and economically suitable for septage disposal has created public opposition due to geographical or environmental concerns. Thus, it could be argued that a suitable site to be used for landfill could prove equally, if not more, difficult to find. The marginal advantage in operating costs for landfill could therefore prove insignificant in the decision process. It might therefore appear that the most practical alternative to cogeneration would be incineration.

The results of the financial analysis conducted on the three methods of refuse disposal by landfill, incineration and cogeneration are summarized in TABLE IV. A comparison is also included in the table to show the marginal difference in operating costs between cogeneration and landfill, and between cogeneration and incineration.

It is evident from the table that the financial benefits gained from operating a Cogeneration plant are significantly greater than those obtained from operating either an Incineration plant or a landfill site. Indeed, after 5 years of operation, both SYSTEM A and SYSTEM D will cost less to operate per year than either an Incineration plant or a landfill site. Futher, over the 25 year period the landfill site or the Incineration plant could cost the CRD an additional $70 to $107 million in 1981 dollars through lost revenues.

However, the major drawback to cogeneration is the large negative cash flows that would be experienced in the first few years of operation. It should be noted, however, that, if incineration is considered to be the more viable alternative to cogeneration, the marginal difference in the two total net annual cash flows up to 1989, which is the year in which a Cogeneration plant would operate at a lower net annual cost than either an Incineration plant or a landfill site, is only an additional $9.06 million for SYSTEM D, and $8.62 million for SYSTEM A, over and above the total negative annual cash flows of the Incineration plant during the same period of operation. The total negative annual cash flows for the disposal of refuse by incineration up to 1989 is $16.85 million. Further analysis and alternative methods of financing the large deficits in the first few years of operation of the Cogeneration plant are the subject of PART III of the report.

PART III

ALTERNATIVE OPTIONS

FOR

FINANCING INITIAL

YEARS NEGATIVE CASH FLOWS

1.00 INTRODUCTION

In PART II of the report it has been demonstrated that a Cogeneration plant would appear to be the most attractive economic solution to disposing of refuse in the VMA. However, such a plant is highly capital intensive, requiring large amortized payments of principal and interest. These payments, although equal in money terms, will erode in real terms as inflation discounts the value of money. However, in the initial years of operation before inflation becomes significant, the payments represent the major operating expense and, as a result, the plant will experience substantial negative cash flows.

In the corporate sector these negative cash flows could be financed by profits from other investments and attractive capital cash allowances of the plant on corporate taxes. However, in the public sector, the negative cash flows have to be financed by other means, and in particular, by Provincial, Regional, and Municipal taxpayers. PART III of the report reviews some of the methods available to finance the initial years of negative cash flows and analyzes the financial liabilities that could be incurred by the various levels of government, should they approve the construction of a Cogeneration plant in the VMA. The total sum of all negative cash flows in the first few years of operation is $30.1 million for SYSTEM D and $33.4 million for SYSTEM A. However, the average annual deficit for SYSTEM D over the 8 years of operating with negative cash flows is $3.8 million per year; while for SYSTEM A, it is $3.3 million per year over 10 years of operating with negative cash flows. SYSTEM D only will therefore be considered in PART III, as it represents the greater annual impact on local government financing.

2.00 SELF FINANCING

Although described earlier as the "investment and opportunity cost" to the owner, column CNR+I of TABLE IV also identifies the results of a specific method of financing the negative cash flows. It has been assumed that any negative cash flow is financed by debt from a commercial financial institution. Interest is paid on the debt at a rate of 18 per cent per year, and is compounded, until such time as the positive cash flows can completely pay off the total debt and interest accrued. It should be noted that, due to inflation at 12 per cent, the interest rate is nearer 5.3 per cent in real terms.

Thus, from column CNR+I, it would appear that SYSTEM D would prove to be completely self financing, as the year 2009 shows a positive balance. This implies that no financing is required by any level of government, either during construction or during operation. In effect, the WMA has a free refuse disposal system.

However, as it has been suggested that The Municipal Act prohibits the financing of current operations by commercial debt, this method cannot be considered too seriously. Further, the debt load would have reached a maximum of $52.7 million by 1996, and this amount is nearly equal to the original capital cost.

Indeed, as the combined debt load would be in excess of $100 million, it is doubtful whether the projected positive cash flows alone would offer sufficient inducement for the financial institution to advance the loan. However, this method of financing has been described to illustrate the economical viability of constructing a Cogeneration plant and to show that, in the last resort, it could prove to be entirely self-financing.

3.00 GOVERNMENT GRANT

Should the construction or operation of a Cogeneration plant qualify for either a Provincial or Federal government grant, then consideration should be given as to how the grant could be most effectively applied. There are many ways in which government can provide financial assistance to a project but, in the case of a Cogeneration plant, only two need be examined below.

a) Capital Cost Grant

A capital cost grant, applied to the total capital cost of a Cogeneration plant, would have the effect of reducing the total capital cost which has to be amortized. The sensitivity analysis applied to the total capital cost in Subsection "5.60 Sensitivity Analysis" of PART I of the report examines the financial implications of reducing the total capital cost by means of a government grant. The results of the sensitivity analysis are summarized in TABLE II.

It will be seen, however, from TABLE V, that with a grant of $13.6 million, the total negative cash flows in the initial years is reduced by $11.4 million while a grant of $27.3 reduced the total negative cash flows in the initial years by $21.2 million. Thus, it would appear that for every dollar given towards the capital cost of the plant, only some percentage of that dollar would assist the financing of the negative cash flows in the initial years. It should be noted, however, that this percentage is still relatively large.

The major effect of a capital cost grant is to shift the graphical plot of the annual net annual cash flows towards the 1985 axis. This not only reduces the number of years of negative cash flows, but the longer term benefits are greatly increased. A grant of $13.6 million will yield an additional $18.5 million over the 25 years of operation, while a grant of $27.3 million would yield an equivalent $37.1 million. Both amounts represent a gross return of 36 per cent in real terms.

Should abnormal inflation or market conditions cause a greater increase in the total capital cost than has been assumed, then the capital cost government grant would best be utilized in keeping the total capital cost to the predetermined budget. The capital cost government grant is not as effective in reducing the negative cash flows in the earlier years as the method described below.

b) Operating Grant

An operating grant applied directly to the negative cash flows in the initial years of operation would be the most effective method of assistance the government could provide in reducing these negative cash flows. The grant could be applied annually or given as a lump sum payment at the commencement of operations. If short-term or medium-term money funds, yielding rates greater than the rate of inflation were available, the lump sum payment could be less than the sum of the negative cash flows due to the interest that has accumulated in real terms during the period of investment. However, for purposes of financial analysis, it has been assumed that the lump sum payment could be invested to yield a rate equivalent to the rate of inflation. Thus, the lump sum payment would be equivalent to providing annual grants, the total of which would equal the lump sum payment.

The maximum grant that need be applied to completely eliminate all of the negative cash flows would be $30.1 million. No further benefits will be gained in the long term as the cumulative net revenue/expenditure or NPV in the year 2009 increases only by the amount of the grant. The average annual net revenue produced by the plant over the 25 years, however, will rise from $1.75 million per year to $3.0 million per year.

If the complete elimination of all negative cash flows by the government grant proves unacceptable to government authorities, then consideration could be given to financing only the marginal difference in negative cash

flows between utilizing a Cogeneration plant or a more conventional system of refuse disposal. For example, for only that period in which the negative cash flows of cogeneration exceed the negative cash flows of an alternative method of refuse disposal, the total marginal difference in negative cash flows between cogeneration and incineration is $9.1 million. However, the total marginal difference in negative cash flows between cogeneration and a new landfill site would be $11.3 million. Should grants be given to offset either of these marginal differences then, the average revenue produced by the Cogeneration plant over the 25 year period would increase from $1.75 million per year to $2.1 million per year for the $9.1 million grant and from 1.75 million per year to $2.2 million per year for the $11.3 million grant.

4.00 CAPITAL REGIONAL DISTRICT PROPERTY TAXES

Any costs associated with refuse disposal are allocated by the CRD to the various municipalities, townships, districts, and electoral areas by a combination of costs per capita and the Assessed Value of Improvements for School Purposes. The Letters Patent indicate that the operational costs of refuse disposal should be distributed in the ratio of 75 per cent by population and 25 per cent by Assessed Value of Improvements for School Purposes. The current figures utilized by the CRD are the 1976 census with a population of 230,592 and the 1981 Assessed Value of Improvements for School Purposes of $577,613,601. The amount which each regional member pays towards refuse disposal can then be calculated from the population and the Assessed Value of Improvements for School Purposes of each regional member. The percentage of the total refuse disposal costs as allocated to each regional member by this method is summarized in TABLE VI.

It should be noted, however, that the Letters Patent limit the costs of refuse disposal which can be allocated by a mill rate to regional members. The Letters Patent may therefore require modification if a Cogeneration plant is constructed.

As many of the individual regional members, being autonomous, are free to levy such taxes, and in such a manner as is necessary to finance their allocated cost of refuse disposal, no attempt will therefore be made to determine the effect of the allocated cost of refuse disposal upon the taxpayers of each regional member. However, as a guideline only, the average mill rate has been calculated which would have to be charged upon the total Taxable School/Hospital Assessments of the CRD. The total value of Taxable School/Hospital Assessments within the CRD for 1981 is $1,127,695,127. The mill rate is therefore 0.887 mills for every $1.0 million of refuse disposal costs.

It must be stressed that no attempt has been made to determine the real increase with time of the Taxable School/Hospital Assessments due either to the growth in population or a real increase in property values. Thus the 1981 assessment value has been assumed to be constant in 1981 dollars over the period of operation of the Cogeneration plant. However, it can be concluded that should any real increase in the Taxable School/Hospital Assessment value occur during this period then the mill rate will correspondingly decrease from the assumed value of 0.887 mills for every $1.0 million of refuse disposal costs.

Based on the above assumption, TABLE VII shows the effect on the overall average mill rate for community members of the CRD for operating the Cogeneration plant and the two alternatives of refuse disposal. A comparison between the two alternatives and the Cogeneration plant is included in the table to show the marginal difference in the mill rate.

5.00 COMMERCIAL REFUSE DISPOSAL FEE

As is current practice, a fee can be charged to all users who dispose of refuse at any of the CRD's facilities. This fee is based upon the gross tonnage of refuse that is received at the gate of the disposal facility. It has been assumed that a common fee would be charged at the existing landfill site and the Cogeneration plant if a Cogeneration plant was constructed. It has been further assumed that the fee, once applied, will not be increased in money terms during the 25 year period. This fee schedule will enable larger revenues to be generated in the initial years when financing of the negative cash flows are required. Although the annual gross tonnage will increase every year, the fee will be reduced in real terms as inflation discounts its value.

GRAPH III shows the annual revenues in 1981 dollars received from the equivalent fee of $12.72/ton in 1981 dollars but first imposed in 1985 and kept thereafter at a fixed rate in money terms of $20.00 per ton. TABLE VIII shows the results of similar calculations but for different initial fee rates. GRAPH III also shows, for reference only, the average net annual cost per ton of refuse for the three alternative methods of refuse disposal.

6.00 CONCLUSIONS

Clearly, any combination of the above methods of financing could be arranged in order to accommodate the total negative cash flows within the inital years of operating the Cogeneration plant. Illustrated in Graph IV is one particular combination which offers an equitable allocation of the liabilities to three parties. It can be seen from the graph that the total negative cash flows of $30.08 million have been allocated in the following manner:

Government Grant	$ 9.96 million
CRD Property Taxes	$10.00 million
Commercial Refuse Disposal Fee	$10.12 million
Total	$30.08 million

The $10.12 million revenue received from the commercial refuse disposal fee is based upon an equivalent fee of $6.36 in 1981 dollars but first imposed in 1985 and kept thereafter at a fixed rate of $10 per ton in money terms. The revenue received from this source will exceed the negative cash flow by $0.3 million in 1992. The option is then available at that time, to discontinue charging the fee. However, if the fee is maintained to 2009, the additional revenue received would amount to $8.3 million in 1981 dollars.

The CRD would finance $10.0 million through property taxes. The first five years of operation would require a contribution of $1.7 million per year but the sixth year (1990) and seventh year (1991) would only require $1.1 million and $0.3 million respectively. Based on a Value of Taxable School/Hospital Assessments of $1,127,695,127, the average mill rate for regional members of the CRD would be 1.52 mills for five years, and 0.99 mills and 0.28 mills for the sixth and seventh years respectively. TABLE IX shows the complete schedule of mill rates for the Cogeneration plant for the 25 year period if the refuse disposal fee is maintained.

For reference, the mill rates that would be required to finance the negative cash flows of an Incineration plant and landfill site, have also been included in TABLE IX. The negative cash flows for these two facilities represent the total operating costs less the revenue received from the commercial refuse disposal fee. The refuse disposal fee would have to be maintained for the 25 year period in order to minimize costs. No government grant has been included in the negative cash flows as neither incineration nor landfill pursues the government objective of energy conservation.

The government might consider financing the balance of the initial years of negative cash flows by grant, either in annual but inequal installments or by a lump sum payment at commencement of operations. If the lump sum payment is invested in money funds yielding a rate of interest equal to the rate of inflation, then the total grant required in either case would be $9.96 million. This amount would closely approximate the marginal difference in negative cash flows between cogeneration and either alternative method of refuse disposal over the period in which the negative cash flows of cogeneration exceed the negative cash flows of an alternative method of refuse disposal.

In summary, it must be stressed that this particular combination of the various methods of financing the negative cash flows experienced in the inital years of the plant's operation is only provided as an illustration. However, the illustration does demonstrate that those initial years of operation can be financed with the assistance of a government grant of less than 20 per cent of the total capital cost and without having to place an excessive burden upon the local taxpayers and commercial users. Further, the marginal difference in the operating costs between cogeneration and either alternative method of refuse disposal, in the initial years of operation,are more than sufficiently compensated in the longer term.

APPENDIX I

TABLES

TABLE I
SUMMARY OF FINANCIAL RESULTS

CASE NUMBER	CASE TITLE	YEAR 1985		LAST YEAR OF NEGATIVE NR			YEAR 2009			
		NR $MILLION	NPC $/TON	YEAR	CNR $MILLION	CNR + I $MILLION	NR $MILLION	NPC $/TON	CNR $MILLION	CNR + I $MILLION
WITH PHASE II CAPACITY										
2	SYSTEM I-w/II	-6.1	-37	2002	-43.5	-82.3	+2.2	+8	-34.7	-108.8
3	SYSTEM II-w/II	-6.1	-37	2007	-57.4	-129.8	+0.4	+1	-56.8	-143.5
4	SYSTEM A-w/II	-6.7	-41	1994	-32.7	-45.7	+4.4	+17	-11.1	-76.8
5	SYSTEM B-w/II	-7.9	-48	1994	-40.2	-55.8	+7.3	+28	+6.2	-66.7
6	SYSTEM C-w/II	-7.3	-44	2002	-53.4	-100.8	+2.0	+8	-46.2	-137.3
7	SYSTEM D-w/II	-7.3	-44	1992	-29.6	-38.3	+7.8	+30	+27.0	-20.8
8	SYSTEM E-w/II	-8.5	-51	1993	-36.1	-49.0	+10.7	+41	+46.9	-4.9
WITHOUT PHASE II CAPACITY										
9	SYSTEM I-w/oII	-6.1	-37	1997	-35.0	-55.2	+3.1	+12	-15.1	-79.1
10	SYSTEM II-w/oII	-6.1	-37	2001	-42.8	-79.1	+1.3	+5	-37.2	-113.8
11	SYSTEM A-w/oII	-6.7	-41	1994	-32.7	-45.7	+5.3	+21	+8.5	-47.1
12	SYSTEM B-w/oII	-7.9	-48	1994	-40.2	-55.8	+8.2	+32	+25.8	-36.9
13	SYSTEM C-w/oII	-7.3	-44	1998	-43.8	-72.2	+2.9	+12	-26.6	-107.6
14	SYSTEM D-w/oII	-7.3	-44	1992	-29.6	-38.3	+8.8	+34	+46.6	+8.9
15	SYSTEM E-w/oII	-8.5	-51	1993	-36.1	-49.0	+11.5	+44	+65.8	+23.3
WITHOUT ELECTRICAL CAPACITY - SYSTEMS A & D ONLY										
16	SYSTEM A-w/II-w/o ELECT	-6.0	-36	2000	-36.5	-65.5	+3.0	+12	-22.1	-88.0
17	SYSTEM A-w/oII-w/o ELECT	-6.0	-36	1996	-32.1	-48.9	+3.9	+15	-5.3	-63.0
18	SYSTEM D-w/II-w/o ELECT	-6.5	-39	1993	-27.3	-37.1	+6.5	+25	+18.1	-28.1
19	SYSTEM D-w/oII-w/o ELECT	-6.5	-39	1993	-27.3	-37.1	+7.4	+29	+34.9	-3.1

TABLE II
SENSITIVITY ANALYSIS

CASE NUMBER	CASE TITLE	YEAR 1985		LAST YEAR OF NEGATIVE NR			YEAR 2009			
		NR $MILLION	NPC $/TON	YEAR	CNR $MILLION	CNR + 1 $MILLION	NR $MILLION	NPC $/TON	CNR $MILLION	CNR + 1 $MILLION
TOTAL CAPITAL COST SYSTEM A										
20	SYSTEM A-w/o II- CONT 50 %	-10.2	-62	1997	-57.4	-91.1	+5.0	+19	-24.9	-130.7
21	SYSTEM A-w/o II- CONT 25 %	-8.5	-51	1996	-44.7	-68.3	+5.1	+20	-8.2	-88.9
11	SYSTEM A-w/o II	-6.7	-41	1994	-32.7	-45.7	+5.3	+21	+8.5	-47.1
22	SYSTEM A-w/o II-Grant 25%	-5.0	-30	1993	-22.0	-29.6	+5.5	+21	+23.8	-7.8
23	SYSTEM A-w/o II-Grant 50%	-3.2	-20	1991	-12.3	-15.2	+5.5	+21	+39.1	+27.9
TOTAL CAPITAL COST SYSTEM D										
24	SYSTEM D-w/o II- CONT 50 %	-11.5	-70	1995	-56.4	-82.8	+8.3	+33	+6.7	-91.3
25	SYSTEM D-w/o II- CONT 25 %	-9.4	-57	1994	-42.5	-60.1	+8.5	+33	+26.7	-41.2
14	SYSTEM D-w/o II	-7.3	-44	1992	-29.6	-38.3	+8.8	+34	+46.6	+8.9
26	SYSTEM D-w/o II-Grant 25%	-5.2	-30	1991	-18.2	-22.9	+8.9	+34	+65.1	+49.1
27	SYSTEM D-w/o II-Grant 50%	-3.1	-19	1989	-8.6	-9.9	+9.0	+35	-83.6	+79.2

TABLE III
SENSITIVITY ANALYSIS

CASE NUMBER	CASE TITLE	YEAR 1985		LAST YEAR OF NEGATIVE NR			YEAR 2009			
		NR $MILLION	NPC $/TON	YEAR	CNR $MILLION	CNR + 1 $MILLION	NR $MILLION	NPC $/TON	CNR $MILLION	CNR + 1 $MILLION
INFLATION										
SYSTEM A										
28	SYSTEM A-w/oII-INF 8%	-4.6	-28	1994	-24.0	-30.2	+5.0	+20	+13.4	-7.9
11	SYSTEM A-w/oII	-6.7	-41	1994	-32.7	-45.7	+5.3	+21	+8.5	-47.1
29	SYSTEM A-w/oII-INF 16%	-9.0	-55	1994	-40.4	-62.8	+5.5	+21	+4.3	-107.8
SYSTEM D										
30	SYSTEM D-w/oII-INF 8%	-4.8	-29	1992	-19.3	-23.2	+8.4	+33	+52.5	+41.1
14	SYSTEM D-w/OII	-7.3	-44	1993	-29.6	-38.3	+8.8	+34	+46.6	+8.9
31	SYSTEM D-w/oII-INF 16%	-10.0	-61	1992	-39.0	-54.6	+9.0	+35	+41.6	-50.8
SELLING PRICE OF STEAM										
SYSTEM A										
32	SYSTEM A-w/oII-SP 6	-7.2	-44	1998	-43.1	-71.2	+2.9	+12	-25.6	-105.4
11	SYSTEM A-w/oII	-6.7	-41	1994	-32.7	-45.7	+5.3	+21	+8.5	-47.1
33	SYSTEM A-w/oII-SP 12	-6.2	-38	1992	-25.8	-33.3	+7.7	+30	+42.6	+11.0
SYSTEM D										
34	SYSTEM D-w/oII-SP 6	-8.1	-49	1996	-42.1	-64.5	+5.1	+20	-5.6	-81.2
14	SYSTEM D-w/oII	-7.3	-44	1992	-29.6	-38.3	+3.8	+34	+46.6	+8.9
35	SYSTEM D-w/o-SP 12	-6.4	-39	1990	-21.3	-25.6	+12.4	+48	+98.8	+82.6
RELIABILITY OF RDF BOILER										
SYSTEM A										
26	SYSTEM A-w/oII-REL 77%	-7.0	-54	1996	-38.1	-58.0	+4.0	+15	-10.8	-80.2
11	SYSTEM A-w/oII	-6.7	-41	1994	-32.7	-45.7	+5.3	+21	+8.5	-47.1
SYSTEM D										
37	SYSTEM D-w/oII-REL 77%	-7.7	-60	1994	-35.7	-50.2	+6.8	+27	+18.6	-39.4
14	SYSTEM D-w/oII	-7.3	-44	1992	-29.6	-38.3	+8.8	+34	+46.6	+8.9

TABLE IV

FINANCIAL COMPARISION OF ALTERNATIVE REFUSE DISPOSAL METHODS

REFUSE DISPOSAL METHOD	YEAR 1985		YEAR 1994			YEAR 2009				AVERAGE COST OVER 25 YEARS	
	NR $MILLION	GPC $/TON	NR $MILLION	GPC $/TON	CNR $MILLION	NR $MILLION	GPC $/TON	CNR $MILLION	CNR + I $MILLION	COST/YR $MILLIONS/YR	GPC $/TON
ALTERNATIVES TO COGENERATION											
LANDFILL	-3.4	-19.3	-2.0	-9.5	-25.9	-1.8	-6.0	-53.1	-114.8	-2.1	-9.1
INCINERATION	-3.8	-21.7	-2.5	-11.4	-30.0	-2.3	-7.6	-63.7	-135.7	-2.5	-10.9
COGENERATION											
SYSTEM A	-6.8	-38.6	-0.4	-2.0	-33.4	+5.1	+16.9	+5.8	-51.6	+0.2	+1.0
SYSTEM D	-7.3	-41.9	+0.6	+3.0	-29.4	+8.5	+28.2	+43.9	+4.4	+1.8	+7.6
MARGINAL DIFFERENCE BETWEEN COGENERATION SYSTEM A AND ALTERNATIVE:-											
LANDFILL	-3.4	-19.3	+1.6	+7.5	-7.5	+6.9	+22.9	+58.9	+63.2	+2.3	+10.1
INCINERATION	-3.0	-16.9	+2.1	+9.4	-3.4	+7.4	+24.5	+69.5	+84.1	+2.7	+11.9
SYSTEM D AND ALTERNATIVE:-											
LANDFILL	-3.9	-22.6	+2.6	+12.5	-3.5	+10.3	+34.2	+97.0	+119.2	+3.9	+16.7
INCINERATION	-3.5	-20.2	+3.1	+14.4	+0.6	+10.8	+35.8	+107.6	+140.1	+4.3	+18.5

TABLE V

EFFECT ON FINANCIAL RESULTS DUE TO DIRECT GRANT APPLIED TO CAPITAL COSTS

GRANT				SAVINGS	
%	Amount $million	YEAR	CNR	Amount $million	% of Grant
EFFECT IN YEAR 1985					
0	0.0	1985	-7.3	0.0	0
25	13.6	1985	-5.2	+2.1	15
50	27.3	1985	-3.1	+4.2	15
EFFECT IN LAST YEAR OF NEGATIVE NR					
0	0.0	1992	-30.1	0.0	0
25	13.6	1991	-18.7	+11.4	84
50	27.3	1989	-8.9	+21.2	78
EFFECT IN YEAR 2009					
0	0.0	2009	+43.9	0.0	0
25	13.6	2009	+62.4	+18.5	136
50	27.3	2009	+81.0	+37.1	136

AVERAGE NR PER YEAR

		AVERAGE NR PER YEAR -$MILLIONS/YEAR
0	-	+1.8
25	13.6	+2.5
50	27.3	+3.2

TABLE VI

PERCENTAGE DISTRIBUTION OF NR TO REGIONAL MEMBERS OF THE C.R.D.

REGIONAL MEMBER	DISTRIBUTION OF NR
Central Saanich	3.6 %
Colwood	4.0 %
Esquimalt	6.0 %
Langford	5.3 %
Metchosin	1.2 %
North Saanich	2.4 %
Oak Bay	7.4 %
Outer Gulf Islands	1.2 %
Saanich	30.5 %
Salt Spring Island	2.1 %
Sidney	3.0 %
Sooke	2.7 %
Victoria	28.9 %
View Royal	1.7 %
	TOTAL 100.0 %

TABLE VII

COMPARISON OF MILL RATE FOR ALTERNATIVE REFUSE DISPOSAL METHODS

REFUSE DISPOSAL METHOD	NCR TO THAT YEAR $MILLIONS	AVERAGE NR TO THAT YEAR $MILLIONS/YR	AVERAGE MILL RATE TO THAT YEAR MILLS/YR.
FIRST YEAR TO 1985			
LANDFILL	-3.38	-3.38	+3.00
INCINERATION	-3.80	-3.80	+3.38
COGENERATION	-7.34	-7.34	+6.51
MARGINAL DIFFERENCE BETWEEN COGENERATION AND:-			
LANDFILL	-3.96	-3.96	+3.51
INCINERATION	-3.54	-3.54	+3.13
FIRST FIVE YEARS TO 1989			
LANDFILL	-14.79	-2.96	+2.62
INCINERATION	-16.85	-3.37	+2.99
COGENERATION	-25.91	-5.18	+4.59
MARGINAL DIFFERENCE BETWEEN COGENERATION AND:-			
LANDFILL	-11.12	-2.22	+1.97
INCINERATION	-9.06	-1.81	+1.61
FIRST TWENTY-FIVE YEARS TO 2009			
LANDFILL	-53.13	-2.13	+1.88
INCINERATION	-63.67	-2.55	+2.26
COGENERATION	+43.93	+1.76	-1.56
MARGINAL DIFFERENCE BETWEEN COGENERATION AND:-			
LANDFILL	+97.06	+3.89	-3.44
INCINERATION	+107.60	+4.31	-3.82

TABLE VIII

REVENUE RECEIVED FROM COMMERCIAL

REFUSE DISPOSAL FEE

FEE	
First Applied in 1985 with 1985 Dollars	Equivalent Value in 1981 Dollars
5.00	3.18
7.87	5.00
10.00	6.36
15.00	9.53
15.74	10.00
20.00	12.71
23.60	15.00

FEE	NR			CNR	
in 1981 dollars per ton	in million 1981 dollars			in million 1981 dollars	
1981	1985	1992	2009	1992	2009
3.18	0.88	0.47	0.10	5.21	9.06
5.00	1.38	0.74	0.16	8.20	14.25
6.36	1.75	0.93	0.20	10.43	18.12
9.53	2.63	1.40	0.30	15.63	27.18
10.00	2.75	1.46	0.31	16.40	28.51
12.71	3.50	1.86	0.40	20.84	36.24
15.00	4.14	2.20	0.47	24.59	42.76

TABLE IX

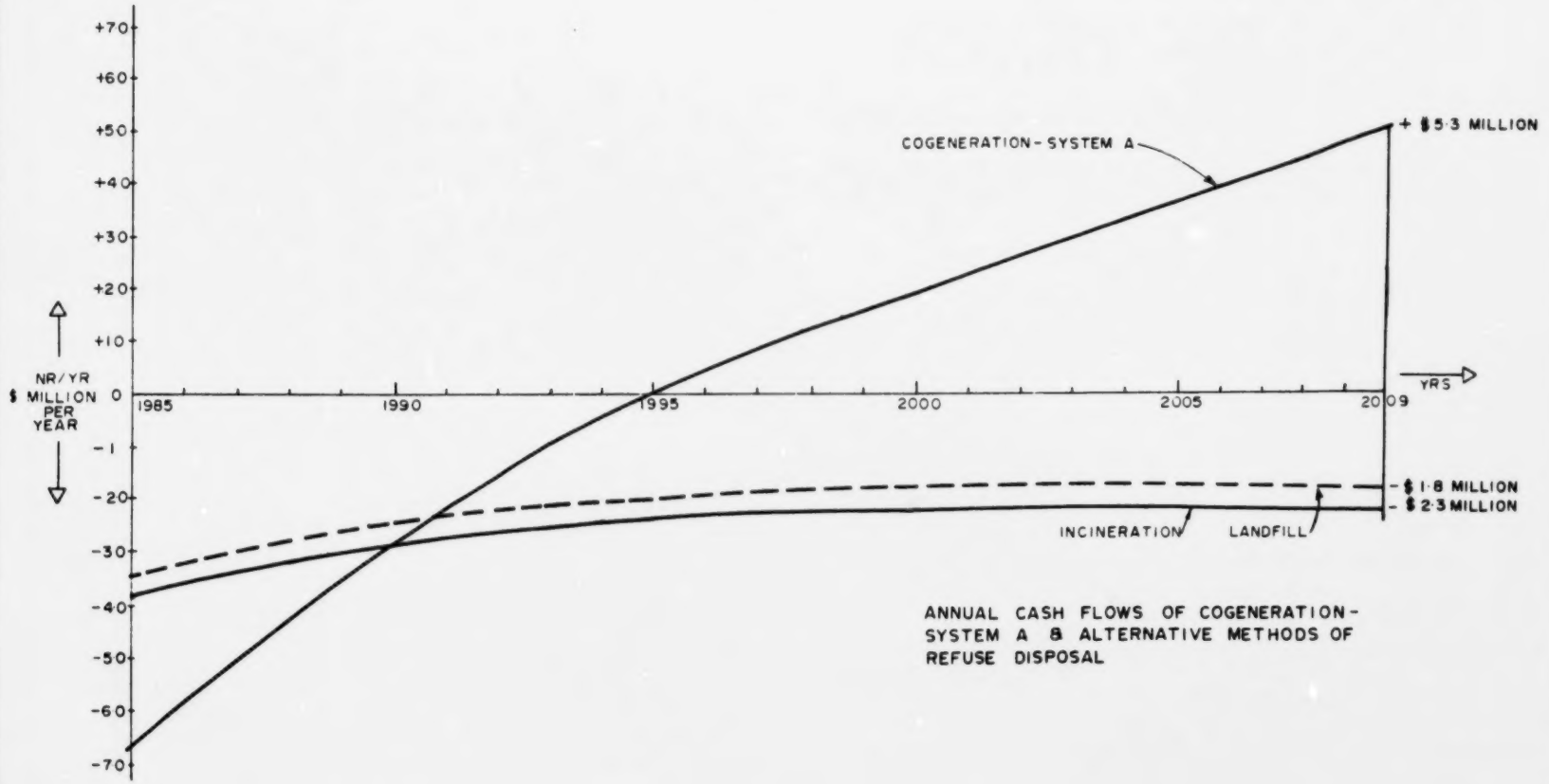
ILLUSTRATION OF A METHOD OF FINANCING NEGATIVE CASH FLOWS

TITLES	UNITS	YEARS 1985	1986	1987	1988	1989	1990	1991	1992	TOTAL FOR YEARS 1985-1992	AVERAGE FOR YEARS 1985-1992	TOTAL FOR YEARS 1993-2009	AVERAGE FOR YEARS 1993-2009
COGENERATION													
NR COGENERATION	$MILLIONS/YR	-7.34	-6.19	-5.12	-4.11	-3.15	-2.22	-1.33	-0.62	-30.08	-3.76	+74.01	+4.35
NR REFUSE FEE	$MILLIONS/YR	+1.75	+1.60	+1.46	+1.34	+1.22	+1.11	+1.02	+0.62	+10.12	+1.27	+8.00	+0.47
GRANT	$MILLIONS/YR	+3.87	+2.88	+1.94	+1.06	+0.21	-	-	-	+9.96	+1.24	-	-
TAXES	$MILLIONS/YR	+1.72	+1.71	+1.72	+1.71	+1.72	+1.11	+0.31	-	+10.00	+1.25	-82.01	-4.82
MILL RATE	MILLS /YR	+1.52	+1.52	+1.52	+1.52	+1.52	+0.99	+0.28	0.00	+8.87	+1.10	-72.71	-4.28
LANDFILL													
NR LANDFILL	$MILLIONS/YR	-3.38	-3.14	-2.93	-2.75	-2.59	-2.44	-2.33	-2.21	-21.77	-2.72	-31.36	-1.84
NR REFUSE FEE	$MILLIONS/YR	+1.75	+1.60	+1.46	+1.34	+1.22	+1.11	+1.02	+0.93	+10.43	+1.30	+7.69	+0.45
TAXES	$MILLIONS/YR	+1.63	+1.54	+1.47	+1.41	+1.37	+1.33	+1.31	+1.28	+11.34	+1.42	+23.67	+1.39
MILL RATE	MILLS /YR	+1.45	+1.37	+1.30	+1.25	+1.21	+1.18	+1.16	+1.14	+10.06	+1.26	+20.99	+1.23
INCINERATION													
NR INCINERATION	$MILLIONS/YR	-3.80	-3.56	-3.34	-3.16	-2.99	-2.85	-2.73	-2.62	-25.05	-3.13	-38.62	-2.27
NR REFUSE FEE	$MILLIONS/YR	+1.75	+1.60	+1.46	+1.34	+1.22	+1.11	+1.02	+0.93	+10.43	+1.30	+7.69	+0.45
TAXES	$MILLIONS/YR	+2.05	+1.96	+1.88	+1.82	+1.77	+1.74	+1.71	+1.69	+14.62	+1.83	+30.93	+1.82
MILL RATE	MILLS /YR	+1.82	+1.74	+1.67	+1.62	+1.57	+1.54	+1.52	+1.50	+12.98	+1.62	+27.43	+1.61
MARGINAL DIFFERENCE BETWEEN COGENERATION AND ALTERNATIVE:-													
LANDFILL	MILLS /YR	+0.07	+0.15	+0.22	+0.27	+0.31	-0.19	-0.88	-1.14	-1.19	-0.15	-93.70	-5.51
INCINERATION	MILLS /YR	-0.30	-0.22	-0.15	-0.10	-0.05	-0.55	-1.24	-1.50	-4.11	-0.51	-100.14	-5.89

APPENDIX II

GRAPHS

GRAPH I



ANNUAL CASH FLOWS OF COGENERATION - SYSTEM A & ALTERNATIVE METHODS OF REFUSE DISPOSAL

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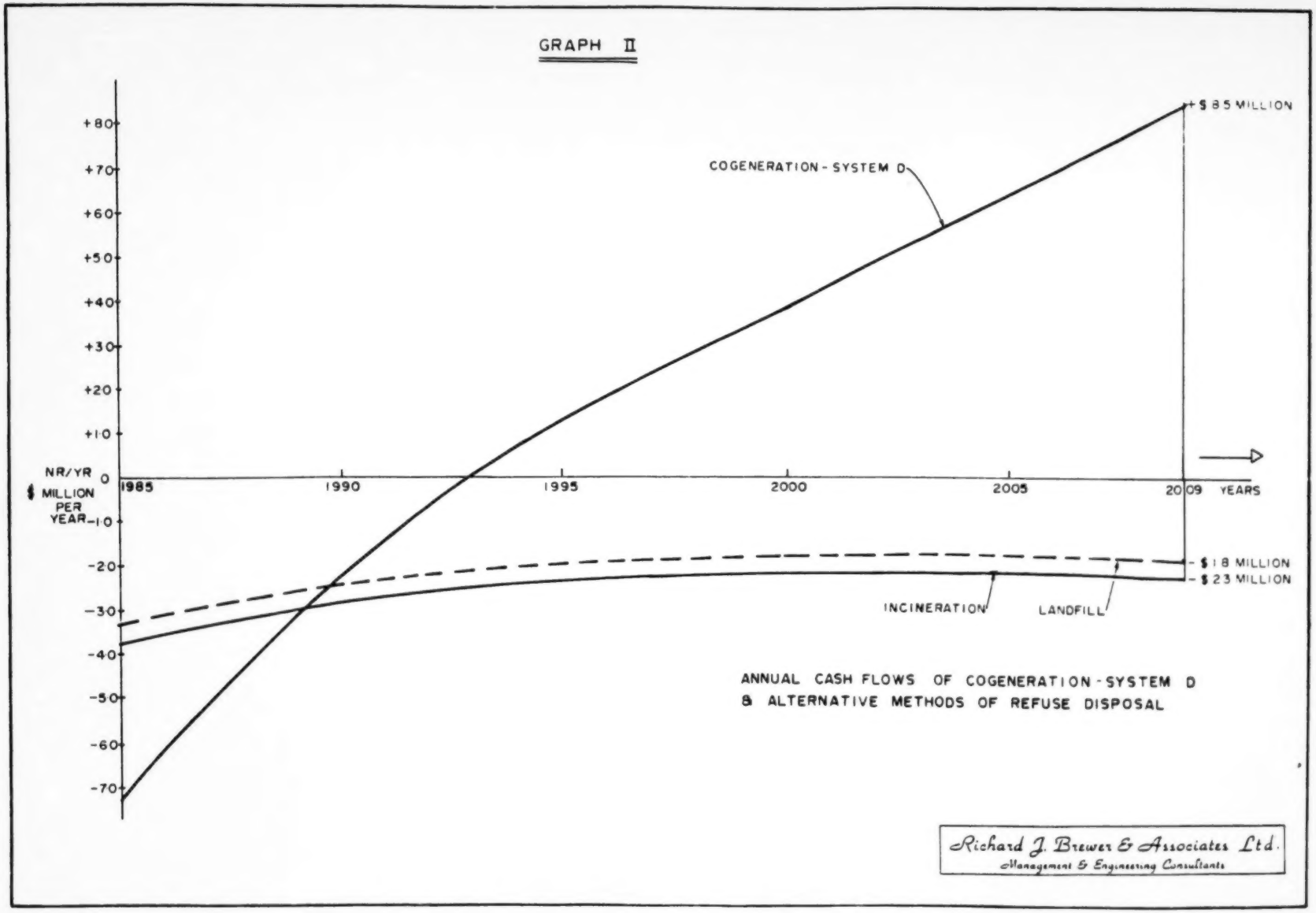
GRAPH II



ANNUAL CASH FLOWS OF COGENERATION - SYSTEM D
& ALTERNATIVE METHODS OF REFUSE DISPOSAL

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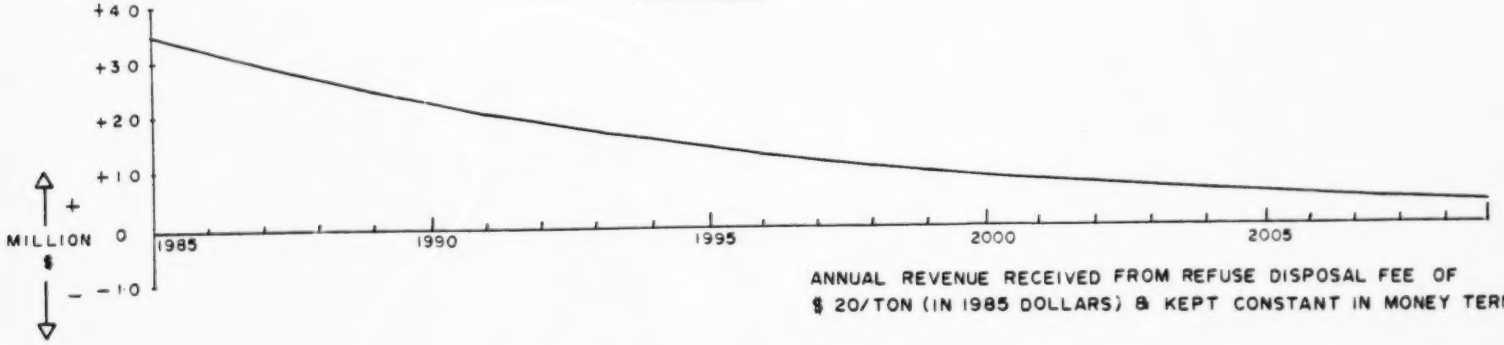
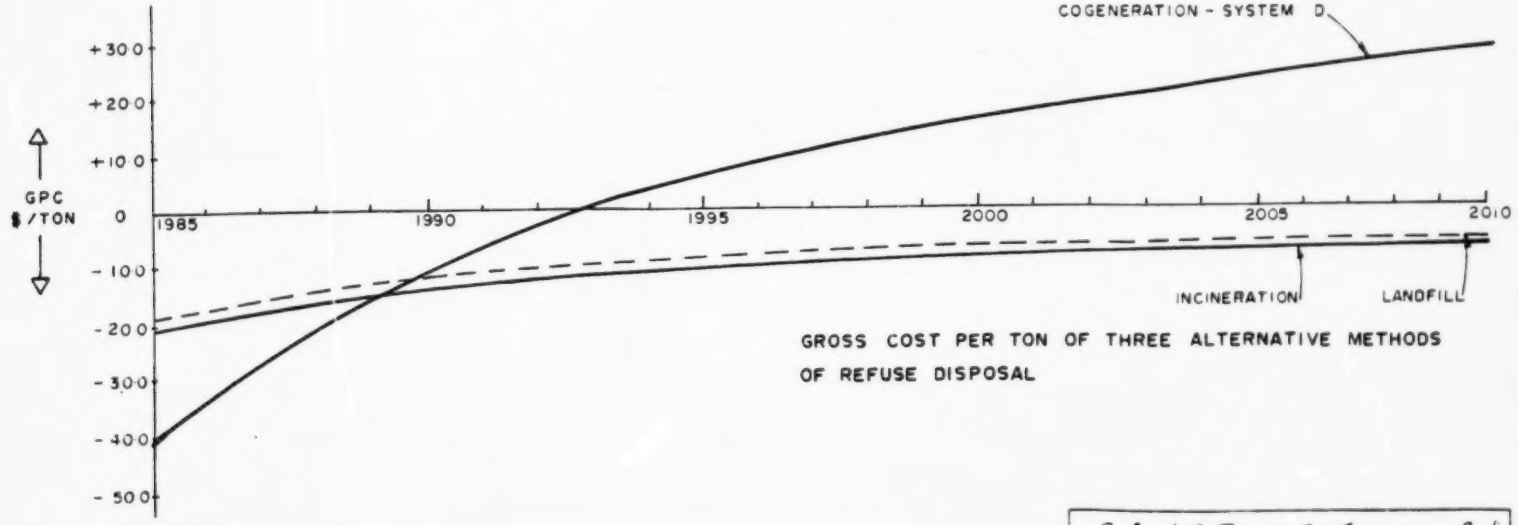
Management & Engineering Consultants

GRAPH III



ANNUAL REVENUE RECEIVED FROM REFUSE DISPOSAL FEE OF $ 20/TON (IN 1985 DOLLARS) & KEPT CONSTANT IN MONEY TERMS



GROSS COST PER TON OF THREE ALTERNATIVE METHODS OF REFUSE DISPOSAL

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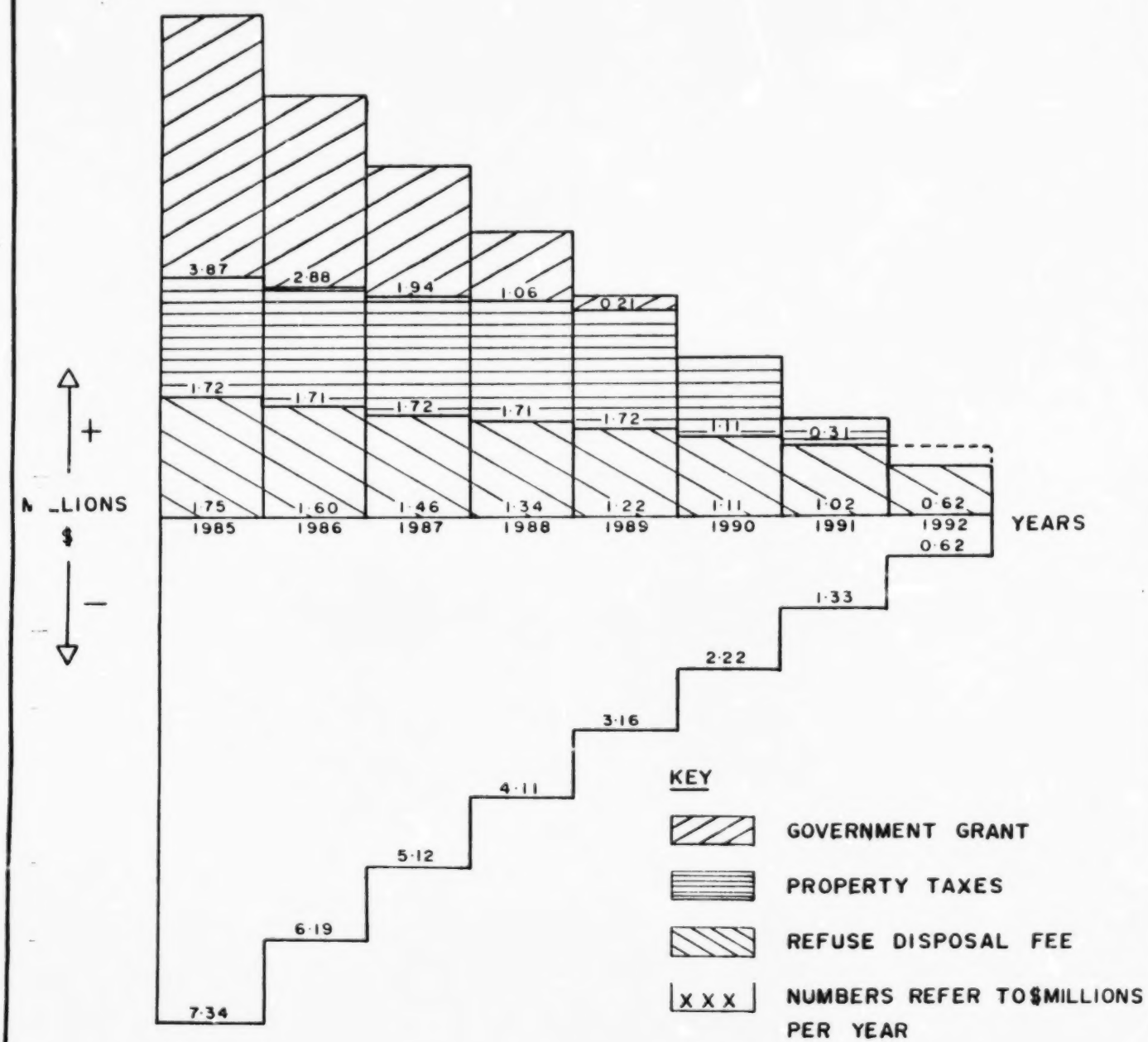
GRAPH IV

ILLUSTRATION OF METHOD OF FINANCING
INITIAL ANNUAL NEGATIVE CASH FLOWS



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APPENDIX .II

INDEX TO VARIABLES UTILIZED

IN FINANCIAL MODEL

INDEX TO VARIABLES UTILIZED IN FINANCIAL MODEL

CO(1)	Total construction costs for Phase I	$
CO(2)	Design/Legal fees	$
CO(3)	Interim financing costs	$
CO(4)	Contingency	$
CO(5)	Total capital cost for Phase I	$
CO(6)	Government grant	$
CO(7)	Net capital cost to CRD for Phase I	$
CO(8)	Net capital cost to CRD for Phase II	$
*C1(1)	Capital cost of land	$
*C1(2)	Construction cost of power plant for Phase I	$
*C1(3)	Construction cost of power plant for Phase II	$
*C1(4)	Construction cost of refuse plant	$
*C1(5)	Construction cost of steam distribution system	$
*C1(6)	Construction cost of electrical distribution system	$
*D1(1)	Percentage increase for design/legal fees	%
*D1(2)	Interest rate for interim financing	%
*D1(3)	Percentage decrease for government grant	%
*D1(4)	Percentage increase for contingency	%
*G1(1)	1981 average daily wet refuse produced in the VMA	tons/day
*G1(2)	Percentage of RDF produced from wet refuse	%
*G1(3)	Percentage of noncombustibles in wet refuse	%
*G1(4)	Percentage of ferrous metals obtained from wet refuse	%
*G1(5)	Percentage of ash produced from wet refuse	%
*G1(6)	Seasonal percentage variation in average daily wet refuse produced in the VMA	%
*G1(7)	Seasonal percentage variation in average hourly volume of steam sold	%
*G1(8)	Maximum capacity of RDF boiler in Phase I	tons(RDF)/day
*I1	Annual rate of inflation	%
*I2	Annual amortization rate of loans	%

*J1	1 ton RDF = X lbs. steam @ 600 psig @ 750°F	lbs/ton
J2(n)	1 ton RDF = Y KWH electricity @ W2(n)% of steam sold	KW/ton
*J3	1 ton RDF = X Imperial gallons of oil	Igall/ton
J4	1 ton RDF = Y KW electricity @ V0(2)% of steam sold	KW/ton
*M0(1)	Refuse plant: initial unit maintenance cost per ton of RDF processed	$/ton(RDF)
*M0(2)	Refuse plant: fixed annual labour costs for Phase I	$/yr.
*M0(3)	Refuse plant: additional fixed annnual labour costs for Phase II	$/yr.
*M0(4)	Refuse plant: fixed annual general costs	$/yr.
*M0(5)	1981 disposal cost per ton of non combustibles	$/ton(NC)
*M0(6)	Refuse plant: unit power requirment to process one ton of RDF	KWH/ton(RDF)
M1(n)	Refuse plant: total annual maintenance costs	$/yr.
M2(n)	Refuse plant: total annual labour costs	$/yr.
M3(n)	Refuse plant: total annual general costs	$/yr.
M4(n)	Refuse plant: total annual power requirement	KW/yr.
M5(n)	Refuse plant: total annual power costs	$/yr.
M6(n)	Total annual volume of noncumbustibles disposed	tons/yr.
M7(n)	Total annual cost of disposing of noncombustibles	$/yr.
N1(1)	Starting year of operation	1985
*N1(2)	Length of simulation	years
*N1(3)	Amortization period for Phase I and Phase II	years
*N1(4)	Number of days of planned downtime of RDF boiler	days
*N1(5)	Reliability of RDF boiler	%
*N1(6)	Number of days of planned downtime of standby boiler	days
*N1(7)	Reliability of standby boiler	%
*N1(8)	Number of days of planned downtime of turbines	days
*N1(9)	Reliability of turbines	%
N2	Number of years remaining for loan after end of simulation	years

*00(1)	Power plant: initial annual maintenance costs for Phase I	$/yr.
*00(2)	Power plant: additional initial annual maintenace costs for Phase II	$/yr.
*00(3)	Power plant: fixed annual labour costs for Phase I	$/yr.
*00(4)	Power plant: additional fixed annual labour costs for Phase II	$/yr.
*00(5)	Power plant: fixed annual general costs for Phase I	$/yr.
*00(6)	Power plant: additional fixed annual general costs for Phase II	$/yr.
*00(7)	Power plant: initial power requirement	KWH
*00(8)	1981 disposal cost per ton of ash	$/ton(ash)
01(n)	Power plant: total annual maintenance costs	$/yr.
02(n)	Power plant: total annual labour costs	$/yr.
03(n)	Power plant: total annual general costs	$/yr.
04(n)	Power plant: total annual power requirement	KW
05(n)	Power plant: total annual power costs	$/yr.
06(n)	Total annual volume of ash disposed	tons/yr.
07(n)	Total annual cost of disposing of ash	$/yr.
08(n)	Annual volume of fuel required for operating the standby boiler during the availability of the standby boiler	Igalls/yr.
09(n)	Annual cost of fuel for operating the standby boiler during the availability of standby boiler	$/yr.
*P0(1)	1981 price per 1,000 lbs/hr of steam sold	$/1000lbsH
*P0(2)	1981 price per 1,000 KWH of electricity sold	$/1000KWH
*P0(3)	Factor to modify unit selling price of electricity to purchase price of electricity	
*P0(4)	Constant monthly revenue from the sale of electrical reliability	$/month
*P0(5)	1981 price per ton of ferrous metals sold	$/ton(FM)
*P0(6)	1981 purchase price per Imperial Gallon of oil	$/Igall.
*P1(n)	Price per 1,000 lbs/hr of steam sold	$
*P2(n)	Price per 1,000 KWH of electricity sold	$
*P4(n)	Price per ton of ferrous metals sold	$/ton(FM)

*R1(1)	Annual percentage growth in average daily wet refuse produced in the VMA	%/yr.
*R1(2)	Annual percentage growth in average hourly volume of steam sold	%/yr.
*R1(3)	Annual percentage growth in price of steam	%/yr.
*R1(4)	Annual percentage growth in price of electricity	%/yr.
*R1(5)	Annual percentage growth in price of ferrous metals	%/yr.
*R1(6)	Annual percentage growth in maintenance costs	%/yr.
*R1(7)	Annual percentage growth in disposal costs	%/yr.
*R1(8)	Annual percentage growth in fuel costs	%/yr.
*T1	Percentage of construction cost of steam and electrical distribution systems utilized for fixed annual operating expenses of distribution systems	%/yr.
*V0(1)	Average initial hourly volume of steam sold	lbs/hr.
*V0(2)	Maximum percentage of steam produced that can be sold	%
*V0(3)	Average maximum hourly volume of steam that can be sold	lbs/hr.
V1(n)	Average hourly volume of steam sold	lbs/hr.
V2(n)	Average hourly volume of electricity sold during availability of RDF boiler	KWH
V3(n)	Average hourly volume of electricity sold during availability of standby boiler	
V4(n)	Average daily volume of ferrous metals sold	tons(FM)/day
V5(n)	Average hourly volume of steam produced during availability of RDF boiler	lbs/hr.
V5(1)	Average hourly volume of steam produced during availability of RDF boiler in first year of operation.	lbs/hr.
V7(n)	Minimum average hourly volume of steam that needs to be produced in order to satisfy average hourly volume of steam that is being sold.	lbs/hr.

WO(n)	Average daily wet refuse processed during availability of refuse plant. N.B. In addition, WO(n) is equivalent to the average daily refuse produced in the VMA. However, should the plant capacity be insufficent to handle the maximum daily refuse produced during the peak period and the excess refuse has to be diverted to an alternative refuse disposal facility then WO(n) is no longer equivalent to the average daily refuse produced in the VMA. WO(n) in this case is defined as the average daily refuse produced in the VMA less the total annual volume of refuse diverted to an alternative refuse disposal facility due to the limited capacity of the plant [X1(n)], divided by 365.	tons/day
W1(n)	Average daily dry RDF processed during availability of refuse plant	tons/day
W2(n)	Ratio of average hourly volume of steam sold to average hourly volume of steam produced	%
W3(1)	Availability of RDF boiler	days
W3(2)	Availability of standby boiler	days
W3(3)	Availability steam supply system	days
W3(4)	Availability of turbines during availability of RDF boiler	days
W3(5)	Availability of turbines during availability of standby boiler	
W3(6)	Program constant	
W3(7)	Program constant	
W4(1)	Annual payment factor on loans	
W4(2)	Annual payment on loan for Phase I	$/yr.
W4(3)	Annual payment on loan for Phase II	$/yr.
W4(4)	Combined annual payment on loans for Phases I & II	$/yr.
W4(5)	Lump sum debt factor for remaining payments on Phase II loan after end of simulation	
W4(6)	Lump sum debt on Phase II loan at end of simulation	$
W4(7)	Lump sum debt on Phase II loan discounted back to 1981 dollars	$
W7(n)	Minimum average daily volume of RDF that is needed to be burnt in order to generate sufficient steam to satisfy average hourly volume of steam that is being sold.	tons RDF/day

W8(n)	Annual volume of fuel for "winter makeup"	Igalls/yr.
W9(n)	Annual cost of fuel for "winter makeup"	$/yr.
X0(n)	Total annual volume of wet refuse that cannot be processed due to the RDF boiler/refuse plant not being in operation.	tons/yr.
X1(n)	Total annual volume of wet refuse that cannot be processed due to the limited capacity of the plant.	tons/yr.
Y1(n)	Total annual revenue received from all sources	$/yr.
Y2(n)	Total annual expenditures paid on all operating costs	$/yr.
Y3(n)	Net annual revenue/expenditure	$/yr.
Y4(n)	Total sum of current and all previous net annual revenue/ expenditures	$
Y5(n)	Total sum of current and all previous net annual revenue/ expenditures with interest being paid on all net expenditures	$
Y6(n)	Average annual gross processing cost per ton of wet refuse produced in the VMA	$/ton
Y7(n)	Average annual net processing cost per ton of wet refuse actually processed through the refuse plant	$/ton
Y8(n)	Average daily volume of disposable material consisting of ash, noncombustible materials and unprocessed wet refuse, sent to an alternative disposal facility	tons/day
Z0(n)	Total Annual distribution system costs	$/yr.
Z1(n)	Total annual revenue from the sale of steam	$/yr.
Z2(n)	Total annual revenue from the sale of electricity	$/yr.
Z3(n)	Total annual revenue from the sale of electrical reliability	$/yr.
Z4(n)	Total annual revenue from the sale of ferrous metals	$/yr.
Z5(n)	Total annual repayment of loans in 1981 dollars	$/yr.
Z6(n)	Total annual power plant expenses	$/yr.
Z7(n)	Total annual refuse plant expenses	$/yr.
Z8(n)	Total annual disposal costs	$/yr.
Z9(n)	Total annual fuel costs	$/yr.

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* NOTICE *

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The computer programme of the financial model is a proprietory software product of Richard J. Brewer & Associates Ltd. and was developed for the sole use of the Capital Regional District.

Further, as the lengthy printout of the computer programme presents some difficulties in its packaging, only a limited number of copies of the programme were printed.

This copy of the report does not, therefore, contain a copy of the computer programme. However, should a copy be specifically required please contact Richard J. Brewer & Associates Ltd., Victoria, B. C.

APPENDIX V

COMPUTER PRINTOUT OF RESULTS

OF TWO SPECIFIC CASES

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 11

SYSTEM A - w/oII

CAPITAL COSTS:

CONSTRUCTION COST OF POWER PLANT	(I)	$	24,500,000
CONSTRUCTION COST OF POWER PLANT	(II)	$	0.000
CONSTRUCTION COST OF REFUSE PLANT	(I)	$	5,000,000
STEAM DISTRIBUTION SYSTEM		$	7,500,000
ELECTRICAL DISTRIBUTION SYSTEM		$	400,000
TOTAL CONSTRUCTION COST	(I)	$	37,400,000
DESIGN/LEGAL FEES @ 10 %	(I)	$	3,740,000
CAPITAL COST OF LAND		$	1,600,000
INTERIM FINANCING @ 18 % p.a.	(I)	$	2,289,643
CONTINGENCY @ 0 %	(I)	$	0.000
TOTAL CAPITAL COST	(I)	$	45,029,643
GOVERNMENT GRANT @ 0 %	(I)	$	0.000
C O S T T O T H E C R D	(I)	$	45,029,643
C O S T T O T H E C R D	(II)	$	0.000

REVENUES:

INITIAL VOLUME OF STEAM SOLD	LBS/HR	16,500
GROWTH IN VOLUME OF STEAM SOLD	% / YR	5.000
PRICE OF STEAM SOLD PER 1000 LBS/HR	$	9.000
GROWTH IN PRICE OF STEAM SOLD	% / YR	5.000
PRICE OF ELECTRICITY SOLD PER 1000KWH	$	13.000
GROWTH IN PRICE OF ELECTRICITY SOLD	% / YR	2.000
PRICE OF FERROUS METALS PER TON	$ / TON	25.000
GROWTH IN PRICE OF METALS SOLD	% / YR	1.000
MONTHLY REVENUE FROM ELEC. RELIABILITY	$ / MON	15,000
MAXIMUM VOLUME OF STEAM SOLD	LBS/HR	24,500
MAX STEAM SOLD TO THAT PRODUCED	%	77.000

EXPENDITURES

POWERPLANT

INITIAL MAINTENANCE COST	(I)	$ / YR	350.000
ADDITIONAL MAINTENENCE COST	(II)	$ / YR	100.000
GROWTH IN MAINTENANCE COST	(I/II)	% / YR	2.000
FIXED LABOUR COST	(I)	$ / YR	420.000
ADDITIONAL LABOUR COST	(II)	$ / YR	120.000
FIXED GENERAL COST	(I)	$ / YR	200.000
ADDITIONAL FIXED GENERAL COST	(II)	$ / YR	50.000

REFUSE PLANT

INITIAL MAINTANANCE COST	(I)	$ / TON	2.000
GROWTH IN MAINTENANCE COST	(I/II)	% / YR	2.000
FIXED LABOUR COST	(I)	$ / YR	420,000
ADDITIONAL LABOUR COST	(II)	$ / YR	300,000
FIXED GENERAL COST	(I/II)	$ / YR	110,000

MISCELLANEOUS

ASH DISPOSAL COST	$ / TON	10.000
INITIAL POWER REQUIREMENT	KWH	250,000
PURCHASE PRICE OF FUEL	$ /10GJ	0.500
GROWTH IN PRICE OF FUEL	% / YR	5.000

MISCELLANEOUS

NONCOMBUSTIBLES DISPOSAL COST	$ / TON	10.000
INITIAL POWER REQUIREMENT	KWH/TN	30.000
PURCHASE TO SELLING FACTOR FOR ELEC.		1.330
GROWTH IN DISPOSAL COST	% / YR	2.500
FIXED STEAM & ELEC. DISTRIBUTION COST	% / YR	0.600

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD

APRIL 1981

SYSTEM A - W/OII

CASE: 11

GENERAL

STARTING YEAR OF CONSTRUCTION	(I)		1983
STARTING YEAR OF OPERATION	(I)		1985
STARTING YEAR OF CONSTRUCTION	(II)		0.000
STARTING YEAR OF OPERATION	(II)		0.000
LENGTH OF SIMULATION		YEARS	25.000
LAST YEAR OF SIMULATION			2009
AMORTIZATION PERIOD	(I)	YEARS	25.000
AMORTIZATION PERIOD	(II)	YEARS	25.000
AMORTIZATION RATE		% / YR	15.000
RATE OF INFLATION		% / YR	12.000
1 TON RDF = X LBS STEAM		X =	8.800
1 TON RDF = X IMP. GAL. OF FUEL		X =	64.170
MAXIMUM CAPACITY OF RDF PLANT		TN/DAY	400.000
SEASONAL VARIATION IN STEAM SOLD		%	25.000

INITIAL AVERAGE WET REFUSE	TNS/DY	438.000
SEASONAL VARIATION IN WET REFUSE	%	32.000
GROWTH IN WET REFUSE	% / YR	2.300
RDF PRODUCED FROM WET REFUSE	%	50.000
INITIAL AVERAGE DRY RDF PRODUCED	TNS/DY	219.000
NONCOMBUSTIBLES FROM WET REFUSE	%	18.700
FERROUS METALS FROM WET REFUSE	%	4.200
ASH PRODUCED FROM WET REFUSE	%	4.000
DOWNTIME OF RDF BOILER	DAYS	15.000
RELIABILITY OF RDF BOILER	%	98.000
DOWNTIME OF STANDBY BOILER	DAYS	5.000
RELIABILITY OF STANDBY BOILER	%	98.000
DOWNTIME OF TURBINES	DAYS	10.000
RELIABILITY OF TURBINES	%	96.000
AVAILABILITY OF REFUSE PLANT	DAYS	343.000
AVAILABILITY OF STEAM SUPPLY SYSTEM	DAYS	364.560
AVAILABILITY OF ELEC. SUPPLY SYSTEM	DAYS	340.389
AVAILABILITY OF STANDBY BOILER	DAYS	21.560

DEBT REMAINING AT YEAR 2010 (II) : $ 0

RELATIONSHIP TO CONVERT 1 TON OF RDF TO PRODUCE Y KWH AT X % OF STEAM SOLD: $Y = 770 - 5.3291\,X + 0.0156\,X^2$

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 11

SYSTEM A - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

REVENUES:

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
STEAM VOLUME (LBS/HR)	16500	17325	18191	19101	20056	21059	22112	23217	24378	24500
STEAM PRICE ($/1000LB/HR)	11	11	12	13	13	14	15	15	16	17
REVENUE	1579	1741	1920	2116	2333	2573	2836	3127	3447	3638
ELEC. VOLUME (KWH)	6751	6882	7015	7151	7288	7426	7567	7710	7854	8058
ELEC. PRICE ($/1000 KWH)	14	14	15	15	15	16	16	16	16	17
REVENUE	738	767	798	830	863	897	933	970	1008	1055
METAL REVENUE	180	186	192	198	205	212	219	226	234	241
ELEC. REI. REV.	180	180	180	180	180	180	180	180	180	180
TOTAL REVENUE	2677	2874	3090	3325	3581	3862	4168	4503	4869	5114

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 11

SYSTEM A - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

EXPENDITURES:

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
LOAN REPAYMENT	6966	6220	5553	4958	4427	3953	3529	3151	2813	2512
POWER PLANT	1135	1147	1159	1172	1185	1198	1212	1226	1241	1256
REFUSE PLANT	741	750	759	769	780	791	802	814	826	839
DISTRIBUTION SYS.	47	47	47	47	47	47	47	47	47	47
DISPOSAL COSTS	412	432	453	475	499	523	548	575	603	632
FUEL COSTS	79	87	96	105	116	128	141	156	172	181
TOTAL EXPENDITURES:	9380	8683	8068	7528	7054	6640	6280	5969	5702	5468
NET REV./EXPEND.	-6703	-5808	-4978	-4203	-3472	-2778	-2112	-1466	-833	-354
CUMMULATIVE NET REV./EXPEND.	-6703	-12511	-17490	-21693	-25165	-27943	-30055	-31522	-32355	-32709
CUMMULATIVE NET REV./ EXPEND. WITH INTEREST ON NET EXPENDITURES	-6703	-12871	-18538	-23734	-28478	-32782	-36650	-40080	-43060	-45721
DISPOSABLE MATERIAL (TONS/DAY)	131	134	137	141	144	147	150	154	157	161
GROSS PROCESS COST ($ PER TON)	-38	-32	-27	-22	-18	-14	-11	-7	-4	-2
NET PROCESS COST ($ PER TON)	-41	-35	-29	-24	-19	-15	-11	-8	-4	-2

COGENERATION

COGEN VERSION 81.131 RJP/RR-CRD APRIL 1981 CASE: 11

SYSTEM A - w/oil

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

REVENUES:

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
STEAM VOLUME (LBS/HR)	24500	24500	24500	24500	24500	24500	24500	24500	24500	24500
STEAM PRICE ($/1000LB/HR)	18	19	20	21	22	23	24	25	26	28
REVENUE	3820	4011	4211	4422	4643	4875	5119	5375	5644	5926
ELEC. VOLUME (KWH)	8273	8490	8699	8901	9096	9284	9464	9637	9803	9962
ELEC. PRICE ($/1000 KWH)	17	17	18	18	19	19	19	20	20	20
REVENUE	1104	1155	1207	1260	1313	1366	1420	1475	1530	1586
METAL REVENUE	249	257	266	274	282	290	298	305	313	321
ELEC. REL. REV.	180	180	180	180	180	180	180	180	180	180
TOTAL REVENUE	5353	5604	5864	6135	6417	6711	7017	7335	7667	8012

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 11

SYSTEM A - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

EXPENDITURES:

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
LOAN REPAYMENT	2243	2003	1788	1596	1425	1273	1136	1015	906	809
POWER PLANT	1272	1288	1305	1321	1338	1355	1373	1390	1408	1427
REFUSE PLANT	852	866	880	895	909	924	938	953	968	983
DISTRIBUTION SYS.	47	47	47	47	47	47	47	47	47	47
DISPOSAL COSTS	663	694	727	760	794	829	864	900	936	973
FUEL COSTS	190	200	210	220	231	243	255	268	281	295
TOTAL EXPENDITURES:	5268	5099	4957	4840	4745	4670	4613	4573	4547	4534
NET REV./EXPEND.	86	505	907	1295	1672	2041	2403	2762	3120	3478
CUMMULATIVE NET REV./EXPEND.	-32623	-32118	-31211	-29915	-28243	-26202	-23799	-21037	-17917	-14439
CUMMULATIVE NET REV./ EXPEND. WITH INTEREST ON NET EXPENDITURES	-48085	-50156	-51935	-53422	-54612	-55497	-56066	-56308	-56204	-55737
DISPOSABLE MATERIAL (TONS/DAY)	165	169	173	179	184	191	198	206	215	224
GROSS PROCESS COST ($ PER TON)	0	2	4	6	7	8	10	11	12	13
NET PROCESS COST ($ PER TON)	0	2	4	6	7	9	10	12	13	14

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 11

SYSTEM A - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

REVENUES:

	2005	2006	2007	2008	2009					
STEAM VOLUME (LBS/HR)	24500	24500	24500	24500	24500					
STEAM PRICE ($/1000LB/HR)	29	30	32	34	35					
REVENUE	6222	6533	6960	7203	7563					
ELEC. VOLUME (KWH)	10114	10259	10398	10530	10655					
ELEC. PRICE ($/1000 KWH)	21	21	22	22	23					
REVENUE	1642	1699	1756	1813	1871					
METAL REVENUE	328	336	343	351	358					
ELEC. REL. REV.	180	180	180	180	180					
TOTAL REVENUE	8372	8748	9139	9547	9972					

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 11

SYSTEM A - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

EXPENDITURES:

	2005	2006	2007	2008	2009
LOAN REPAYMENT	722	645	576	514	459
POWER PLANT	1445	1464	1483	1502	1522
REFUSE PLANT	999	1014	1030	1045	1061
DISTRIBUTION SYS.	47	47	47	47	47
DISPOSAL COSTS	1011	1049	1089	1128	1169
FUEL COSTS	310	325	342	359	377
TOTAL EXPENDITURES:	4534	4545	4566	4596	4635
NET REV./EXPEND.	3838	4203	4573	4951	5337
CUMMULATIVE NET REV./EXPEND.	-10600	-6398	-1825	3126	8463
CUMMULATIVE NET REV./ EXPEND. WITH INTEREST ON NET EXPENDITURES	-54885	-53622	-51922	-49753	-47081
DISPOSABLE MATERIAL (TONS/DAY)	234	245	257	269	282
GROSS PROCESS COST ($ PER TON)	14	15	16	17	18
NET PROCESS COST ($ PER TON)	16	17	18	19	21

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM D - w/oII

CAPITAL COSTS:

CONSTRUCTION COST OF POWER PLANT	(I)	$	24,500,000
CONSTRUCTION COST OF POWER PLANT	(II)	$	0.000
CONSTRUCTION COST OF REFUSE PLANT	(I)	$	5,000,000
STEAM DISTRIBUTION SYSTEM		$	15,700,000
ELECTRICAL DISTRIBUTION SYSTEM		$	400,000
TOTAL CONSTRUCTION COST	(I)	$	45,600,000
DESIGN/LEGAL FEES @ 10 %	(I)	$	4,560,000
CAPITAL COST OF LAND		$	1,600,000
INTERIM FINANCING @ 18 % p.a.	(I)	$	2,772,857
CONTINGENCY @ 0 %	(I)	$	0.000
TOTAL CAPITAL COST	(I)	$	54,532,857
GOVERNMENT GRANT @ 0 %	(I)	$	0.000
C O S T T O T H E C R D	(I)	$	54,532,857
C O S T T O T H E C R D	(II)	$	0.000

REVENUES:

INITIAL VOLUME OF STEAM SOLD	LBS/HR	27,500
GROWTH IN VOLUME OF STEAM SOLD	% / YR	5.000
PRICE OF STEAM SOLD PER 1000 LBS/HR	$	9.000
GROWTH IN PRICE OF STEAM SOLD	% / YR	5.000
PRICE OF ELECTRICITY SOLD PER 1000KWH	$	13.000
GROWTH IN PRICE OF ELECTRICITY SOLD	% / YR	2.000
PRICE OF FERROUS METALS PER TON	$ / TON	25.000
GROWTH IN PRICE OF METALS SOLD	% / YR	1.000
MONTHLY REVENUE FROM ELEC. RELIABILITY	$ / MON	15,000
MAXIMUM VOLUME OF STEAM SOLD	LBS/HR	37,000
MAX STEAM SOLD TO THAT PRODUCED	%	77.000

EXPENDITURES

POWERPLANT

INITIAL MAINTENANCE COST	(I)	$ / YR	350,000
ADDITIONAL MAINTENENCE COST	(II)	$ / YR	100,000
GROWTH IN MAINTENANCE COST	(I/II)	% / YR	2.000
FIXED LABOUR COST	(I)	$ / YR	470,000
ADDITIONAL LABOUR COST	(II)	$ / YR	120,000
FIXED GENERAL COST	(I)	$ / YR	200,000
ADDITIONAL FIXED GENERAL COST	(II)	$ / YR	50,000

REFUSE PLANT

INITIAL MAINTANANCE COST	(I)	$ / TON	2.000
GROWTH IN MAINTENANCE COST	(I/II)	% / YR	2.000
FIXED LABOUR COST	(I)	$ / YR	420,000
ADDITIONAL LABOUR COST	(II)	$ / YR	300,000
FIXED GENERAL COST	(I/II)	$ / YR	110,000

MISCELLANEOUS

ASH DISPOSAL COST	$ / TON	10.000
INITIAL POWER REQUIREMENT	KWH	750.000
PURCHASE PRICE OF FUEL	$ /IGAL	0.800
GROWTH IN PRICE OF FUEL	% / YR	5.000

MISCELLANEOUS

NONCOMBUSTIBLES DISPOSAL COST	$ / TON	10.000
INITIAL POWER REQUIREMENT	KWH/TN	30.000
PURCHASE TO SELLING FACTOR FOR ELEC.		1.330
GROWTH IN DISPOSAL COST	% / YR	2.500
FIXED STEAM & ELEC. DISTRIBUTION COST	% / YR	0.600

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM 0 - w/oII

GENERAL

STARTING YEAR OF CONSTRUCTION	(I)		1983
STARTING YEAR OF OPERATION	(I)		1985
STARTING YEAR OF CONSTRUCTION	(II)		0.000
STARTING YEAR OF OPERATION	(II)		0.000
LENGTH OF SIMULATION		YEARS	25.000
LAST YEAR OF SIMULATION			2009
AMORTIZATION PERIOD	(I)	YEARS	25.000
AMORTIZATION PERIOD	(II)	YEARS	25.000
AMORTIZATION RATE		% / YR	15.000
RATE OF INFLATION		% / YR	12.000
1 TON RDF = X LBS STEAM		X =	8,800
1 TON RDF = X IMP. GAL. OF FUEL		X =	64.170
MAXIMUM CAPACITY OF RDF PLANT		TN/DAY	400.000
SEASONAL VARIATION IN STEAM SOLD		%	75.000

DEBT REMAINING AT YEAR 2010 (II) : $ 0

INITIAL AVERAGE WET REFUSE	TNS/DY	438.000
SEASONAL VARIATION IN WET REFUSE	%	32.000
GROWTH IN WET REFUSE	% / YR	2.300
RDF PRODUCED FROM WET REFUSE	%	50.000
INITIAL AVERAGE DRY RDF PRODUCED	TNS/DY	219.000
NONCOMBUSTIBLES FROM WET REFUSE	%	18.700
FERROUS METALS FROM WET REFUSE	%	4.200
ASH PRODUCED FROM WET REFUSE	%	4.000
DOWNTIME OF RDF BOILER	DAYS	15.000
RELIABILITY OF RDF BOILER	%	98.000
DOWNTIME OF STANDBY BOILER	DAYS	5.000
RELIABILITY OF STANDBY BOILER	%	98.000
DOWNTIME OF TURBINES	DAYS	10.000
RELIABILITY OF TURBINES	%	96.000
AVAILABILITY OF REFUSE PLANT	DAYS	343.000
AVAILABILITY OF STEAM SUPPLY SYSTEM	DAYS	364.560
AVAILABILITY OF ELEC. SUPPLY SYSTEM	DAYS	340.389
AVAILABILITY OF STANDBY BOILER	DAYS	21.560

RELATIONSHIP TO CONVERT 1 TON OF RDF TO PRODUCE Y KWH AT X % OF STEAM SOLD: $Y = 770 - 5.3291\ X + 0.0156\ X^2$

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM D - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

REVENUES:

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
STEAM VOLUME (LBS/HR)	27500	28875	30319	31835	33426	35098	36853	37000	37000	37000
STEAM PRICE ($/1000LB/HR)	11	11	12	13	13	14	15	15	16	17
REVENUE	2632	2902	3199	3527	3889	4288	4727	4983	5232	5494
ELEC. VOLUME (KWH)	6182	6288	6394	6502	6609	6718	6827	7018	7220	7427
ELEC. PRICE ($/1000 KWH)	14	14	15	15	15	16	16	16	16	17
REVENUE	681	707	734	762	790	820	850	891	935	980
METAL REVENUE	180	186	192	198	205	212	219	226	234	241
ELEC. REL. REV.	180	180	180	180	180	180	180	180	180	180
TOTAL REVENUE	3673	3975	4305	4667	5064	5499	5976	6280	6580	6895

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM D - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

EXPENDITURES:

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
LOAN REPAYMENT	8436	7532	6725	6005	5361	4787	4274	3816	3407	3042
POWER PLANT	1135	1147	1159	1172	1185	1198	1212	1226	1241	1256
REFUSE PLANT	741	750	759	769	780	791	802	814	826	839
DISTRIBUTION SYS.	97	97	97	97	97	97	97	97	97	97
DISPOSAL COSTS	412	432	453	475	498	523	548	575	603	632
FUEL COSTS	133	150	171	196	226	263	306	310	311	313
TOTAL EXPENDITURES:	10954	10108	9364	8714	8147	7658	7239	6837	6484	6179
NET REV./EXPEND.	-7280	-6133	-5059	-4047	-3083	-2159	-1263	-557	96	717
CUMMULATIVE NET REV./EXPEND.	-7280	-13414	-18473	-22519	-25603	-27761	-29024	-29581	-29485	-28768
CUMMULATIVE NET REV./ EXPEND. WITH INTEREST ON NET EXPENDITURES	-7280	-13804	-19602	-24699	-29105	-32823	-35844	-38321	-40278	-41719
DISPOSABLE MATERIAL (TONS/DAY)	131	134	137	141	144	147	150	154	157	161
GROSS PROCESS COST ($ PER TON)	-42	-34	-28	-22	-16	-11	-6	-3	0	3
NET PROCESS COST ($ PER TON)	-44	-36	-29	-23	-17	-12	-7	-3	0	4

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM D - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

REVENUES:

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
STEAM VOLUME (LBS/HR)	37000	37000	37000	37000	37000	37000	37000	37000	37000	37000
STEAM PRICE ($/1000LB/HR)	18	19	20	21	22	23	24	25	26	28
REVENUE	5769	6057	6360	6678	7012	7362	7731	8117	8523	8949
ELEC. VOLUME (KWH)	7639	7853	8060	8260	8453	8638	8817	8988	9152	9310
ELEC. PRICE ($/1000 KWH)	17	17	18	18	19	19	19	20	20	20
REVENUE	1028	1077	1127	1177	1228	1280	1332	1385	1438	1491
METAL REVENUE	249	257	266	274	282	290	298	305	313	321
ELEC. REL. REV.	180	180	180	180	180	180	180	180	180	180
TOTAL REVENUE	7226	7572	7933	8309	8702	9112	9540	9987	10454	10941

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD

APRIL 1981

CASE: 14

SYSTEM D - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

EXPENDITURES:

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
LOAN REPAYMENT	2716	2425	2165	1933	1726	1541	1376	1229	1097	980
POWER PLANT	1272	1288	1305	1321	1338	1355	1373	1390	1408	1427
REFUSE PLANT	852	866	880	895	909	924	938	953	968	983
DISTRIBUTION SYS.	97	97	97	97	97	97	97	97	97	97
DISPOSAL COSTS	663	694	727	760	794	829	864	900	936	973
FUEL COSTS	316	321	329	339	352	367	385	404	424	446
TOTAL EXPENDITURES:	5916	5692	5503	5345	5216	5112	5032	4973	4931	4905
NET REV./EXPEND.	1310	1880	2430	2964	3486	4000	4508	5015	5523	6036
CUMMULATIVE NET REV./EXPEND.	-27458	-25579	-23149	-20185	-16699	-12700	-8192	-3177	2346	8382
CUMMULATIVE NET REV./ EXPEND. WITH INTEREST ON NET EXPENDITURES	-42645	-43050	-42926	-42262	-41040	-39239	-36833	-33792	-30079	-25654
DISPOSABLE MATERIAL (TONS/DAY)	165	169	173	179	184	191	198	206	215	224
GROSS PROCESS COST ($ PER TON)	6	8	11	13	14	1(	18	19	21	22
NET PROCESS COST ($ PER TON)	6	9	11	13	16	18	19	21	23	25

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM D - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

REVENUES:

	2005	2006	2007	2008	2009
STEAM VOLUME (LBS/HR)	37000	37000	37000	37000	37000
STEAM PRICE ($/1000LB/HR)	29	30	32	34	35
REVENUE	9397	9866	10360	10878	11422
ELEC. VOLUME (KWH)	9461	9604	9742	9873	9997
ELEC. PRICE ($/1000 KWH)	21	21	22	22	23
REVENUE	1545	1600	1655	1710	1766
METAL REVENUE	328	336	343	351	358
ELEC. REL. REV.	180	180	180	180	180
TOTAL REVENUE	11450	11982	12538	13118	13725

COGENERATION

COGEN VERSION 81.131 RJB/RB-CRD — APRIL 1981 — CASE: 14

SYSTEM D - w/oII

STATEMENT OF REVENUE AND EXPENDITURE ($1000)

EXPENDITURES:

	2005	2006	2007	2008	2009
LOAN REPAYMENT	875	781	697	622	556
POWER PLANT	1445	1464	1483	1502	1522
REFUSE PLANT	999	1014	1030	1045	1061
DISTRIBUTION SYS.	97	97	97	97	97
DISPOSAL COSTS	1011	1049	1089	1128	1169
FUEL COSTS	468	491	516	542	569
TOTAL EXPENDITURES:	4894	4896	4911	4937	4973
NET REV./EXPEND.	6557	7086	7627	8182	8752
CUMMULATIVE NET REV./EXPEND.	14939	22025	29652	37833	46586
CUMMULATIVE NET REV./EXPEND. WITH INTEREST ON NET EXPENDITURES	-20472	-14483	-7632	141	8894
DISPOSABLE MATERIAL (TONS/DAY)	234	245	257	269	282
GROSS PROCESS COST ($ PER TON)	24	25	26	28	29
NET PROCESS COST ($ PER TON)	27	28	30	32	34

ADDENDUM

Richard J. Brewer & Associates Ltd.
November, 1981

ADDENDUM

1.00 GENERAL

The report entitled "FINANCIAL ANALYSIS AND ECONOMIC EVALUATION OF THE CONCEPT OF COGENERATION FOR THE VICTORIA METROPOLITAN AREA" by Richard J. Brewer & Associates Ltd. was completed in May 1981. Subsequent to completion of this report a number of events have occurred, which may wish to be considered in conjunction with this report. These events are described in more detail in this section and which forms an addendum to the report.

2.00 FINANCIAL ANALYSIS OF BCFP CASE

2.10 General

It was requested in early September, 1981, that Richard J. Brewer & Associates Ltd. undertake a financial analysis of cogeneration in the VMA utilizing B. C. Forest Products Ltd. (BCFP) as the sole purchaser of the steam produced from the Cogeneration plant. The results were presented to B. H. Levelton & Associates for further review in mid-September.

2.20 Methodology

It was considered essential, that BCFP achieve a reliable source of steam which should be produced either by the RDF boiler, or failing that, by the standby boiler. As any labour difficulties experienced by the CRD could not only shut down the RDF boiler, but also, the standby boiler, it was considered preferable to have BCFP own and operate the standby boiler. As the standby boiler will not be constructed within the Cogeneration plant, the construction cost of the power plant can be reduced by $1.3 million to $23.2 million.

The previous fianancial analyses have been conducted on the basis that sales of steam are independent of production of steam. It was therefore necessary to modify the financial model itself, in order to reflect that all steam produced will be sold to BCFP, providing that the volume of steam produced does not exceed the volume of steam that BCFP requires. The computer programme that is enclosed in APPENDIX V of this report is, therefore, not applicable to the BCFP case. In particular, mathematical relationships accounting for the seasonal variations in steam production had to be modified. In winter, an inadequate amount of steam could be produced from the RDF boiler to meet the BCFP demands and with no standby boiler available, potential revenues from the sale of steam could no longer be realized. In summer, steam produced by the RDF boiler could possibly

be in excess of the BCFP demand and therefore this excess steam will have to be wasted, again, with a corresponding loss of potential revenue.

The Cogeneration plant will sell in any particular year, an average hourly volume of steam. This average hourly volume of steam sold will increase annually with the annual growth in refuse produced in the VMA. It will continue to increase up to the maximum average hourly volume of steam sold, the value of which, has been determined from the data below. However, it should be noted that, due to the seasonal variations of refuse produced in the VMA the growth in the average hourly volume of steam sold will no longer be, as in the previous cases, a constant geometric progression.

Four specific cases were analysed with this modified programme using two different values for the two key variables involved. These are as follows:

	1	2	3	4
Maximum average hourly volume of steam sold (lbs./hr.).	62,670	62,670	68,570	68,570
Selling price of steam ($/1000 lbs.).	7.00	5.00	7.00	5.00

The maximum average hourly volume of steam sold was calculated from the average volume of steam sold over a year containing:

Either:

250 days with 2 shifts @ 100,000 lbs/hr of steam sold

Or:

250 days with 2 shifts @ 112,930 lbs/hr of steam sold

And:

250 days with 1 shift @ 40,000 lbs/hr of steam sold
115 days with 3 shifts @ 25,000 lbs/hr of steam sold

In order to make an equitable comparison with the previous cases that were analyzed, the Cogeneration plant was limited to Phase I construction only; thus the RDF boiler is limited to 400 tons/day of RDF. The maximum volume of steam that can therefore be sold, in any one hour, is 112,930 lbs. Thus this figure was utilized in determining the maximum average hourly volume of steam sold.

The 1981 price of steam was considered to be in the range of $5.00 to $7.00 per 1,000 lbs/hr of steam sold. This price reflects a substantial discount to the purchaser due to bulk sales and competitive prices that BCFP could obtain from burning their own waste products.

Other values of variables which differ from the values utilized in the previous financial analyses are:

Steam Distribution System Construction Cost	$ 2.0 million
Cost of Land	$ 2.5 million

The steam distribution system construction cost was based on approximately half a mile of steam pipeline @ $800 per foot. The capital cost of land was assumed to be higher than originally estimated for the Government Street/Inner Harbour/North of Pandora Street site, due to the possible acquistion of already developed property. Both the capital cost of land and the capital cost of the steam distribution system are subject to modification, resulting from a better estimate, developed from a thorough technicial and real estate appraisal.

As with the previous analyses, only the average hourly volume of steam sold to that produced was utilized in determining the revenue from the sale of electricity. It was considered that the

additional lengthy calculations to account for daily and weekly variations in steam sales and seasonal variations in steam production did not, as in the previous analyses, yield any significantly better results. Further, it should be noted that as no standby boiler is available, the plant can no longer be considered reliable in the production of electricity. Thus, no revenue has been assumed to accrue from this source.

2.30 Results

The results of the four cases are tabulated in TABLE X. An indentical format to that of the earlier tables has been adopted. The conclusions from this analyses are discussed in the main report to be submitted by B. H. Levelton & Associates Ltd.

TABLE X

SUMMARY OF FINANCIAL RESULTS UTILIZING

B. C. FOREST PRODUCTS LTD. AS SOLE PURCHASER OF STEAM

	YEAR 1985	
CASE NUMBER	NR $MILLION	NPC $/TON
1	-3.3	-20
2	-4.5	-27
3	-3.1	-19
4	-4.4	-27

LAST YEAR OF NEGATIVE NR		
YEAR	CNR $MILLION	CNR + I $MILLION
1989	-8.6	-10.0
1991	-16.9	-21.0
1988	-7.4	-8.2
1991	-15.4	-19.3

	YEAR 2009			
CASE NUMBER	NR $MILLION	NPC $/TON	CNR $MILLION	CNR + I $MILLION
1	+11.7	+45	+111.8	+107.8
2	+ 7.7	+30	+ 52.4	+ 36.2
3	+13.0	+50	+129.0	+126.0
4	+ 8.6	+33	+ 64.4	+ 51.6

3.00 ELECTRICITY GENERATED FROM THE STANDBY BOILER

3.10 General

It has already been determined that it is uneconomical to produce superheated steam and electricity from the standby boiler unless a market for the sale of the reject low pressure steam has been established. The question has subsequently been raised, whether it is economical to eliminate the generation of electricity entirely from the steam produced by the standby boiler, and produce only low pressure steam which is sufficient to meet the demands for steam sales. A short financial analysis was therefore implemented, in order to determine the economic viability of producing superheated steam from the standby boiler, and consequently, produce electricity and sufficient low pressure reject steam to meet the steam sales.

3.20 Methodology

The analysis was performed by computing the marginal increase in fuel costs required to raise the low pressure steam to superheated steam in order to generate electricity. The revenue received from the sale of that electricity, was also computed, and a comparison was then made, to determine if the additional costs incurred, could be justified.

The analysis was conducted on one of the two most favoured cases that were presented in this report. The particular case was entitled SYSTEM D-W/OII. The results of the analyis are summarized below for the total revenue/fuel costs which were received/expended for the 25 years of operation of the standby boiler, during the period that the RDF boiler was not in operation.

However, one of the key factors in the finanacial analysis is the thermal value that can be assigned to one pound of low pressure steam sold. Two values have been selected, one value of 1217 BTU/lb, as

per the report by B. H. Levelton & Associates Ltd. and the other value of 987 BTU/lb. which represents, as has been suggested, 88% of the net heat requirement of 1122 BTU/lb for the superheated steam.

The heating value of fuel was assumed to be 150,000 BTU/US gallon with a conversion efficiency of 85%. The volume of steam produced the volume of steam sold, the cost of the fuel purchased and the price that the electricity commanded over the 25 year period were all identical to those volumes assumed in the original case.

3.30 Results

The following results were obtained from the analysis for operating the standby boiler for 25 years during the period the RDF boiler was not in operation.

Electrical Production

Cost of fuel for superheated steam	$8.23 million
Revenue from electricity	$0.52 million
Revenue from electrical reliability	$4.50 million
Net cost of producing electricity	$3.21 million

No Electrical Production-Steam Value = 1217 BTU/lb

Cost of fuel for low pressure steam	$7.11 million
Net additional cost of not producing electricity	$3.90 million

No Electrical Production-Steam Value = 987 BTU/lb

Cost of fuel for low pressure steam	$5.77 million
Net additional cost of not producing electricity	$2.56 million

3.40 Conclusions

In either case, it is evident that it is more beneficial to produce superheated steam and generate electricity, rather than produce low pressure steam, and no electricity. However, it must be stressed, that inherent in this statement is the assumption that as the electrical reliability of the plant could no longer be maintained, then the annual revenue received from that source must be forfeited. Although this is assumed to be correct, only negotiations with the purchaser of the electricity can verify this. Therefore, based on the above, the average net additional cost of fuel, if electricity was not generated during the operation of the standby boiler, could be as high as $150,000 per year.

4.00 MISCELLANEOUS

4.10 General

Subsequent to the completion of this report in May 1981, a number of events have occurred which could impinge upon the results of the financial analysis. No attempt has been made to assess the impact, if any, of these events upon the economic viability of cogeneration within the VMA. They are, however, merely identified in order that public authorities are cognizant of their existence and that they can be taken into account in the decision making process.

4.20 Interest Rates

Interest rates have been extremely volatile during 1981 especially in the latter half. Long term bonds are becoming increasingly more difficult to obtain without paying a substantial premium.

4.30 National Energy Agreement

In September, 1981, a pricing structure for oil and natural gas was established between the Province of Alberta and the Federal Government of Canada. The Province of British Columbia similarly entered into an agreement with the Federal Government. Although details are known of the Agreement the precise effect on fuel costs over the next few years has not been fully determined.

4.40 Vancouver Island Natural Gas Line

Discussions continue between the various corporate organizations and the Governments of Canada and the Province of British Columbia regarding the construction of a natural gas pipeline to Vancouver Island. Any escalation in construction costs or any delay in the scheduling of the pipeline, may have an impact on fuel costs in the VMA.

Further, a policy of the Provincial Government has indicated that the cost of natural gas sold be fixed at a unit rate throughout the province and that the rate should be a fixed percentage of the cost of oil. Thus, uncertainty remains in establishing a price for the sale of steam.

4.50 Rock Bay Housing Development

The City of Victoria, in the summer of 1981, announced that some 1,200 houses may be constructed in the area known as Rock Bay. As this neighbourhood is generally in the Government Street/Inner Harbour/North of Pandora Street area, the intended location of the Cogeneration plant may have to be revised. However, a new market for the sale of steam could be developed, if an agreement could be reached, for the Cogeneration plant to supply the heating requirements of the houses.

However, no physical construction has taken place to date and rumours are circulating, that the future of the project is uncertain.

4.60 Labatts Brewery

In October 1981, Labatts announced that they would be closing their brewery located on Government Street. The Labatts Brewery had been identified as a potential customer to whom steam could be sold. The loss therefore in potential sales of some 3,300 lbs/hr is considered to be significant.

4.70 Conclusions

No attempt has been made to assess the impact, if any, of the above events upon the economic viability of cogeneration within the VMA. However, before a final decision is made regarding the construction of a Cogeneration plant and as time may clarify some of these issues, public authorities may wish to implement one final analysis to assess the financial impact of the above events.